Near-Term Reliability and Resilience (NTRR) - Final Report

July 2022

ORNL/XXXX

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Forward

This project was funded by the United States Department of Energy's (DOE's) under the Grid Modernization Initiative (GMI) and carried out by a collaborative partnership of six DOE National Laboratories and one National Science Foundation (NSF) Center led by Oak Ridge National Laboratory (ORNL). In addition to ORNL, the Project Team members included Sandia National Laboratory (SNL), National Renewable Energy Laboratory (NREL), National Energy Technology Laboratory (NETL), Argonne National Laboratory (ANL), Lawrence Livermore National Laboratory (LLNL) and The University of Tennessee's NSF CURENT center.

The project team regularly collaborated with several industry partners including North American Electric Reliability Corporation (NERC), ABB Hitachi Energy, PJM Interconnection LLC (PJM) and its member system Dominion Virginia Power (DVP), Southeastern Electric Reliability Corporation (SERC), The Independent System Operator – New England (ISO-NE), The New York Independent System Operator (NYISO), The California Independent System Operator (CAISO), The Reliability First Corporation (RFC), The Western Electric Coordination Council (WECC), The Bonneville Power Administration (BPA), The Public Service of New Mexico (PNM), The American Gas Association (AGA), The Interstate National Gas Association of America (INGAA), Tennessee Valley Authority (TVA), PacifiCorp, FPL NextEra, The Brattle Group, and The Res Group. Additionally, the project team also received input and guidance from many other industry entities and government agencies throughout the project on technical, operational, and data interpretation questions.

A Technical Review Committee (TRC) was established to provide advice and recommendations to the project team. The TRC included experts from grid operating organizations, utility companies that only operate the interconnection, but also own generation, transmission, distribution, and load assets, but also pipeline and gas facilities. The group also included established power system switchgear equipment manufacturers, established power system consulting companies, industry research organizations, grid reliability agencies, and other stakeholders. The following experts participated in the project as members of the TRC:

Participant	Organization	Participant	Organization
Mike Bailey	WECC	Nicholas Phillips	PNM
Saad Malik	WECC	Syed Siddiqui	TVA
Sean Erickson	WAPA	Emmanuel B.	PJM
Brian Fitzpatrick	PJM	Song Wang	PacifiCorp
John Stevenson	NYISO	Kimberly Denbow	American Gas Association
Mike Knowland	ISO-NE	Mike Isper	Interstate Natural Gas Association of America
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Dr. Ryan Quint	NERC	Hannes Pfeifenberger	Brattle Group
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Slava Messlinokov	ISO-NE	Dr. Hongming Zhang	Utilicast
Andrew Arana	FPL	Dave Krueger	SERC

In addition to the TRC, the Project Team actively engaged with the electrical power industry and have been invited for panel sessions and seminars at key industry events, such as the IEEE Power and Energy Society, Summer Meeting 2022, in Denver, Colorado (July 17-21).

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Acronyms and Abbreviations

Acronym	Definition
AC	Alternating Current
ACSR	Aluminum-Conductor Steel-Reinforced
AGA	American Gas Association
AGC	Automatic Gain Control
ANL	Argonne National Laboratory
ANR	American Natural Resources Company Pipeline (TC Energy)
BCF	Billion Cubic Feet
BCF/D	Billion Cubic Feet per Day
BES	Bulk Electric System
BPS	Bulk Power System
CAGR	Capital Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAISO	California Independent System Operator
CAMX	California-Mexico
CBEMA	Computer Business Equipment Manufacturers Association
CEII	Critical Energy Infrastructure Information
CER	Canada Energy Regulator
COI	California-Oregon Intertie
CONUS	Continental U.S.
CO2	Carbon Dioxide
CPF	Continuation Power Flow
CT	Combustion Turbine
CTAIDI	Customer Total Average Interruption Duration Index
DC	Direct Current
DER	Distributed Energy Resource
DEV	Dominion Energy Virginia
DKL	Deep Kernel Learning
DOE	United States Department of Energy
DOT	Department of Transportation
DR	Demand Response
DRI	Dynamic Resilience Indicator
DSCI	Drought Severity and Coverage Index
DSW	Desert Southwest
DVP	Dominion Virginia Power
EBB	Electronic Bulletin Boards
ECP	Electricity Capacity Planning
EENS	Expected Energy Not Served
EERE	Office Energy Efficiency and Renewable Energy
EFD	Electricity Fuel Dispatching
EFDHRS	Equivalent Forced Derated Hours during Reserve Shutdowns
EFDR	Equivalent Forced Derated Hours
EFOR	Equivalent Forced Outage Rate
EFP	Electricity Finance and Pricing
EI	Eastern Interconnection

Acronym	Definition
EIA	Energy Information Administration
EIA AEO	EIA Annual Energy Outlook
ELCC	Effective Load Carrying Capacity
ELD	Electricity Load and Demand
EMM	Electricity Market Module
EMS	Energy Management System
EPA	Environmental Protection Agency
ERAG/MMWG	Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
F	Firm Natural Gas Supply Contract
FA	Frequency Agility
FE	DOE's Office of Fossil Energy
FERC	Federal Energy Regulatory Commission
FIDVR	Fault-Induced Delayed Voltage Recovery
FLEP (ΦΛΕΠ)	Fast (Φ) resilience drops, how Low (Λ) resilience drops, how Extensive (E) the post-degraded state becomes and how Promptly (Π)
FOH	Forced Outage Hours
FOR	Forced Outage Rate
GADS	Generating Availability Data System
GHG	Greenhouse Gas
GMI	Grid Modernization Initiative
GMLC	Grid Modernization Laboratory Consortium
GW	Gigawatt
HIFLD	Homeland Infrastructure Foundation-Level Data
HRR	Higher Renewable Resource
HS	Heavy Summer
HVDC	High Voltage Direct Current
HW	Heavy Winter
I	Interruptible Natural Gas Supply Contract
IA	Interconnection Agreement
IBR	Inverter Based Resources
IEEE	Institute of Electrical and Electronics Engineers
INGAA	Interstate National Gas Association of America
IRP	Integrated Resource Plans
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
ITIC	Information Technology Industry Council
KV	kilovolt
KW	Kilowatt
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkley National Laboratory
LDA	Locational Deliverability Area
LDC	Local Distribution Company
LL	Loadability Limit
LLNL	Lawrence Livermore National Laboratory
LMP	Locational Marginal Price

Acronym	Definition
LNG	Liquified Natural Gas
LOLD	Loss of Load Duration
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LTRA	Long-Term Reliability Assessment
MCS	Monte Carlo Simulation
MISO	Midcontinent Independent System Operator
MMCF	Million Cubic Feet
MMCF/d	Million Cubic Feet per Day
MMWG	Multiregional Modeling Working Group
MTEP	MISO Transmission Expansion Plan
MTTF	Mean-Time-to-Failure
MTTR	Mean-Time-to-repair
MVA	Mega Volt Ampere
MW	Megawatt
NAERM	North American Energy Resilience Model
NCDC	NOAA National Climate Data Center
NDA	Nondisclosure Agreement
NE	Office of Nuclear Energy
NEMS	EIA National Energy Modeling System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGCC	Natural Gas-Fired Combined Cycle
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPCC	Northeast Power Coordinating Council
NPP-NW	Northwest Power Pool Northwest
NREL	National Renewable Energy Laboratory
NSF	National Science Foundation
NS-MCS	Non-sequential MCS
NTRR	Near-Term Reliability and Resilience
NWPP	Northwest Power Pool (Now WPP-Western Power Pool)
NWPP-C	NWPP Central
NWPP-NE	NWPP Northeast
NWS	National Weather Service
NYISO	New York Independent System Operator
OH	Ohio
ORNL	Oak Ridge National Laboratory
PCM	Production Cost Model
PDCI	Pacific DC Intertie
PG&E	Pacific Gas and Electric Company
PHMSA	Department of Transportation Pipeline and Hazardous Materials Safety Administration
PJM	Pennsylvania Jersey Maryland Interconnection
PNM	Public Service of New Mexico
POI	Point of Interconnection
PPF	Probabilistic Power Flow

Acronym	Definition
PRC	Protection & Control
PSS/E	Power System Simulator for Engineers
PUC	Public Utilities Commission
PV	Photovoltaics
QGESS	Quality Guideline for Energy System Studies
RA	Resource Adequacy
RC	Recirculating Cooling
REs	Regional Entities
RFC	Reliability First Corporation
RNA	Reliability Needs Assessment
RPS	Renewable Portfolio Standard
RR	Reactive Reserve
RTO	Regional Transmission Operator
RTS	Reliability Test System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCE	Southern California Edison
SCMVA	Short Circuit MVA
SCR	Short Circuit Ratio
SCRIF	Short Circuit Ratio with Interaction Factor
SE	State Estimation
SERC	Southeastern Electric Reliability Council
SH	Service Hours
SNL	Sandia National Laboratory
SO_2	Sulfur Dioxide
SoCal Gas	Southern California Gas Company
SOW	Statement of Work
SPP	Southwest Power Pool
SRI	Severity Risk index
ST	Steam Turbine
TADS	Transmission Availability Data System
TCO Pool	Columbia Gas Transmission Pool
Tetco	Texas Eastern Transmission Company
THI	Temperature-Humidity Index
Transco	Transcontinental Gas Pipeline (Williams Companies)
TRC	Technical Review Committee
TRE	Texas Reliability Entity
TVA	Tennessee Valley Authority
UC	Under Construction
UGS	Underground Natural Gas Storage
UOM	Unit of Measure
US	United States
USDA	United States Department of Agriculture
USDM	U.S. Drought Monitor
USGS	United States Geological Survey
UTK	University of Tennessee Knoxville
VAR	Volt-Amps Reactive
WAPA	Western Area Power Administration

Acronym	Definition
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WSCR	Weighted Short Circuit Ratio
WWP	Winter Weather Parameter
Z6 (non-NY)	Transco Zone 6 (non-New York)

Executive Summary

Introduction

The Near-Term Reliability and Resiliency (NTRR) was awarded in December 2020 as an inter-lab project to examine the reliability and resilience of the electricity grid and natural gas transportation availability. The project builds on studies conducted by The North American Electric Reliability Corporation (NERC), the U.S. Department of Energy (DOE), and other non-governmental research and operational focused on reliability and resilience analyses challenges. The research was conceived to address near-term scenarios (within 10 years), when many local and regional policy transitions could begin to impact grid reliability, resilience, and supporting infrastructure availability.

To integrate the natural gas interdependency, the team began with the generating capacity and demand projections from the 2020 NERC Long-Term Reliability Assessment and the Bulk Electric System (BES) transmission topologies defined in the Western Electricity Coordinating Council (WECC) Anchor Data Set, Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group (ERAG/MMWG) Data Set, the team calculated baseline regional power sector gas demands from present electricity delivery year through the end of delivery year 2030/31 by applying security constrained economic dispatch. This demand was compiled along with demand projections for regional residential, commercial, and industrial natural gas demands from the most recent Energy Information Administration (EIA) Annual Energy Outlook Reference Case into Deloitte's MarketBuilder® North American Gas Model. Through the application of these demands, MarketBuilder® was projected the topology of natural gas flows in the natural gas pipeline network across the interconnected North American system along with regional natural gas prices that may be seen by market participants in future years

Additionally, contingencies and sensitivities focused on the built models of the Eastern Interconnection (EI) and Western Interconnection (WI). They address challenges from the following with the outcomes being an identification of performance under the extreme conditions and an identification of potential grid weaknesses that should be addressed to mitigate the reduced performance and improve the resilience and reliability of the specific regions as well as the National Grid:

- Weather events including extreme heat, extreme cold, high wind, no wind, wind and solar forecasting errors, and wildfires.
- Gas availability, factoring in supply disruption (contractual and physical), seasonal availability constraints, and infrastructure limitations; and
- Transmission availability and congestion.

Project Organization

Figure ES-1 shows the high level NTRR project organization.

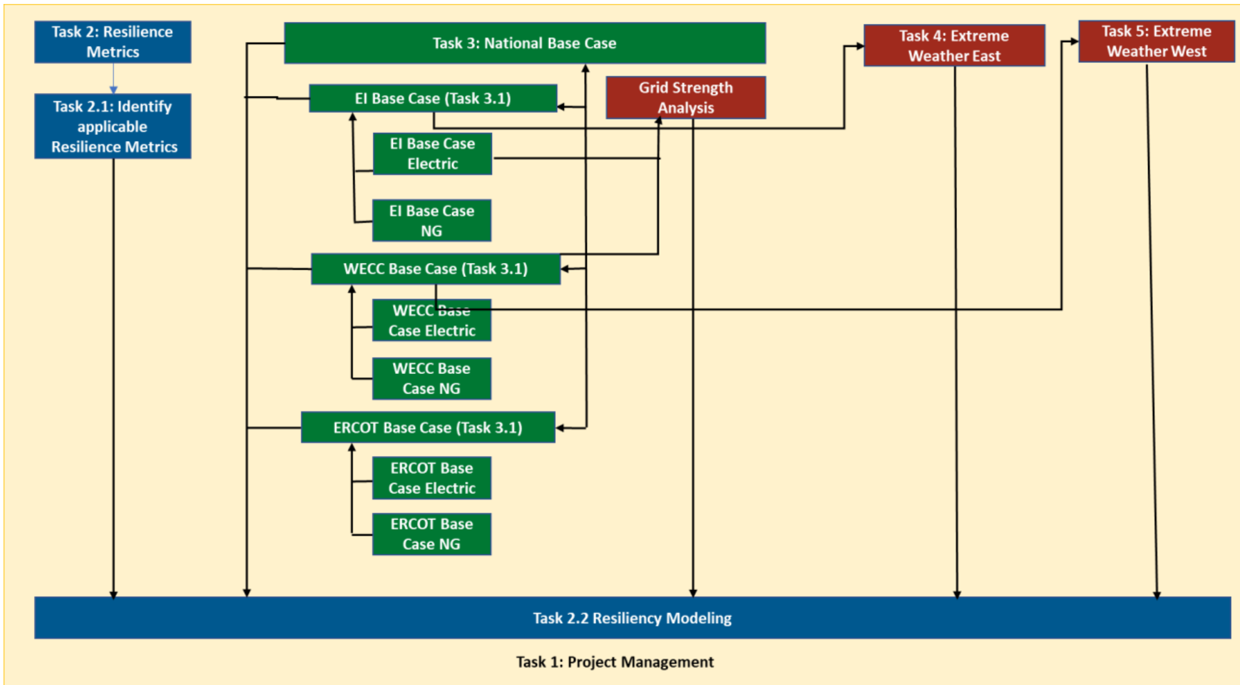


Figure ES-1. NTRR Project Structure and Task Relationships

Project Challenges and Misconceptions

The challenge in analyzing the Near-Term reliability and resilience of the electric grid form a national level is the assumption that the United States has a national electric grid. This assumption is not completely accurate. The electric transmission grid within the United States consists of three (3) Interconnections EI), WI, and The Electric Reliability Council of Texas (ERCOT) Interconnect that operate like semi-independent transmission grids that are loosely connected through both alternating current (AC) and high voltage direct current (HVDC) connections. Additionally, the EI and WI grids are a synchronized grid (same grid frequency), but the ERCOT interconnect is asynchronous (different grid frequency) to both EI and WI interconnects under normal system conditions. Adding to the complexity of analyzing the near – term reliability and resilience from a national level is an underlying natural gas (NG) infrastructure that provides fuel to the natural gas generators. This infrastructure is a well-integrated system of pipelines for "transporting NG" throughout the U.S. This NG infrastructure also faces reliability and resilience challenges such as frozen compressors and inability to pump NG to the generators, thus causing a derating or lessening of the ability of a generator to provide the necessary power to the grid.

This misconception or misunderstanding leads many, even within the industry, to assume that there is a single grid that can mutually assist during normal operations and under extreme conditions. The actual ability for one "region" to support another is limited to the ability to use the few interconnections that exist between the regions. **Figure ES-2** shows EI, WI, and ERCOT and the associated interconnections.

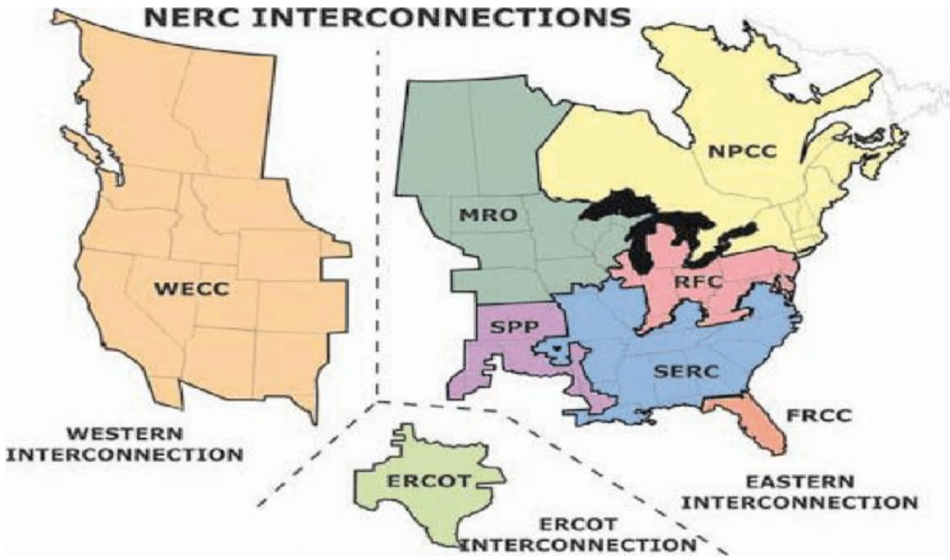


Figure ES-2. National Electric Grid- Three Loosely Connected Regions

Task 2: Resiliency Metrics for the Electric Grid and Natural Gas System

The primary purpose of Task 2 is to be an enabler of apples-to-apples comparison of grid resilience and reliability across electrical interconnections, across the natural gas infrastructure, and across the spectrum of scenarios to show a full national resilience picture. To do this, Task 2 incorporated the results of the other tasks to perform the resilience analysis.

This task identifies and describes the different reliability and resilience metrics used in the NTRR project. The metrics consist of both quantifiable metrics and probabilistic metrics.

- Quantifiable Deterministic Metrics (Grid Reliability and Grid Resilience):
  - **Static security assessment** - Static security assessment determines whether a power system is able to supply peak demand after one or more pieces of equipment (such as a line or a transformer) are disconnected.
  - **Dynamic security assessment** – Dynamic security assessment checks whether a system will reach a steady state after a fault occurs.
- Probabilistic Metrics - Probabilistic criteria such as Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS) address the concerns that contingency criteria does not consider the probability of a contingency occurring or its impact should it occur.
  - **System Adequacy** - System adequacy assessment is probabilistic in nature. Each component of the system has a probability of being available, a probability of being available with a reduced capacity, and a probability of being unavailable. To assess the transmission reliability, it is assumed that the generation is sufficient and the distribution systems serving the loads are operated appropriately. This allows the probability of all transmission state combinations to be computed.

Reliability vs Resilience

A main differentiator between reliability and resilience is the frequency and impact of an event. Reliability focuses on assuring adequate grid operations in typical conditions, through real-time load and generator balancing, and operating equipment within defined limits. Resilience focuses on the operation of the grid during extreme and adverse events, which can be categorized as atypical and emergent conditions. Another distinction between reliability and resilience is that a system may be considered reliable without identifying a specific threat to the system. However, when discussing resilience, systems are considered resilient to a particular threat or set of threats. Hence, reliability metrics do not attribute the cause to the metric (e.g., a load is de-energized without regard to why or how), whereas resilience metrics do consider the cause (e.g., a hurricane caused the load to be de-energized). Therefore, resilience bridges the gap between the system response and a root cause.

Time-Dependent Analysis of an Event

An important aspect of resilience is its time-varying nature. Many of the basic elements of system resilience are captured in different phases before and during a severe event as well as after the event, when the system has been restored. **Figure ES-3** shows an illustrative generic resilience curve where a resilience indicator is used to quantify the resilience level of a power system during an event as a function of time.

- **Pre-disturbance Phase**: The operating point of the system before a severe event occurs. In this state, resources are prepositioned to prepare for an event. Remedial actions are set up to minimize the impact of the event. The metrics that are calculated in this phase include Loss of Load Probability, Planning Reserve Margins, etc. These metrics quantify the generation resource adequacy.
- **Disturbance Phase**: The time between the start of the event to the end of the event. In this phase, the resilience indicator quantifies how fast and how low the resilience drops. This includes the amount of generation megawatt (MW) lost, load MW disconnected, and the rate at which generation, transmission lines, and customers are disconnected during the event.
- **Post-Disturbance and Degraded Phase**: Following the end of the event and just before restoration is initiated is the post-disturbance degraded state. In this stage, the damages caused by the event are assessed and critical components required for recovery are identified.
- **Recovery and Restoration phase**: A resilient system should demonstrate high restorative capabilities in order to restore disconnected customers and collapsed infrastructures. The recovery phase of the event commences at the time the system performance has reached its minimum resilience level and ends at a point in time in which some minimally acceptable and stable level of system performance has been recovered through adaptive actions by the system and its human operators.
- **Post-Restoration Phase**: Following the event and the restoration of the system to an acceptable operational state, the post-restoration phase begins. In this phase, the impact of the event and the performance of the network are thoroughly analyzed to identify the weaknesses and limitations of the network.

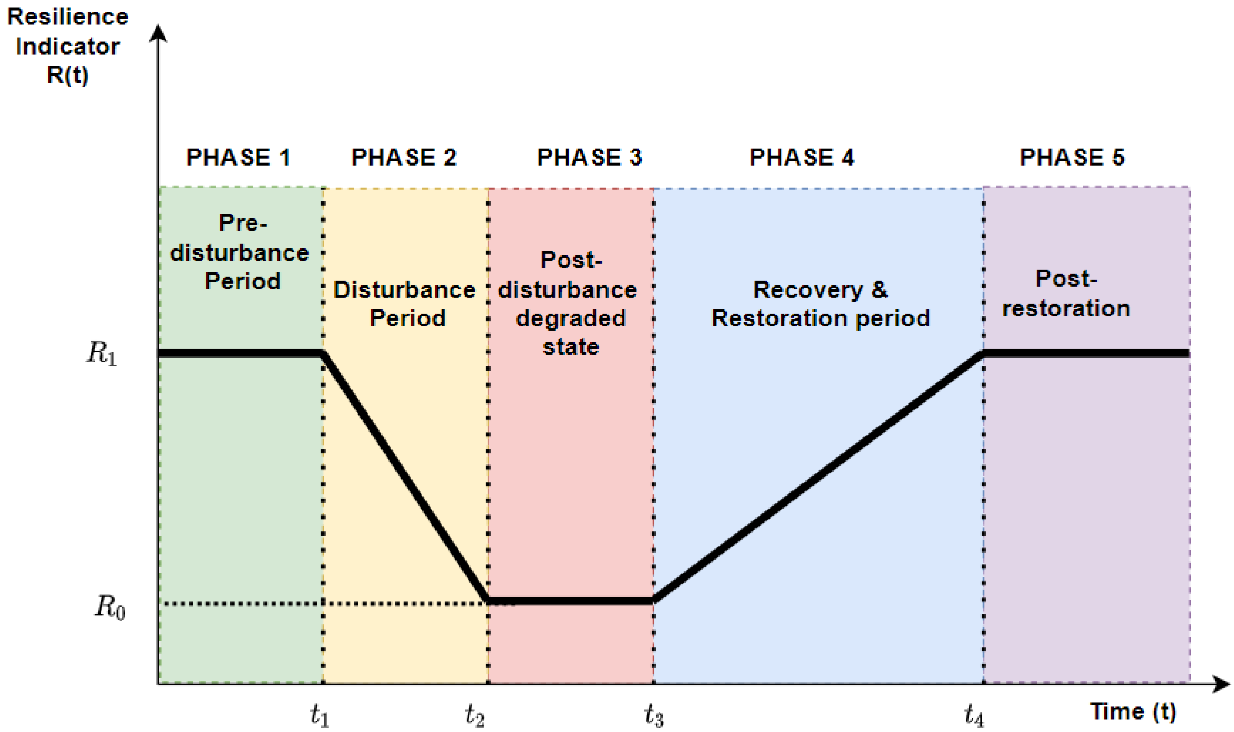


Figure ES-3. Multiphase Trapezoid Curve

Task 3: National Base Case

Introduction

An iterative process was used in the development of the base models including interim reporting on the base model development. In case of conflicts between EIA/NERC data and aggressive state policies, a balance was be achieved with DOE and industry input. Assumptions were be validated with key industry entities, both Technical Review Committee (TRC) members and others, on a best-efforts basis. Both wind and solar locations were based on known projections as well as load and cost analysis together with industry inputs. These locations are directly connected to historical weather years and generation profiles for use in production cost modeling.

The base case scenarios allow for analysis and understanding near future reliability and resiliency risks that arise from an unmanaged or poorly managed transition. Part of the base model development includes identification of issues that arise between the various region and state Renewable Portfolio Standard (RPS) goals. Evaluation of the metrics established in initial project deliverables highlighted system vulnerabilities and could be used to select more impactful sensitivities to evaluate in later tasks.

Figure ES-4 shows the interdependencies of the Electric and gas cases into a combined national base case.

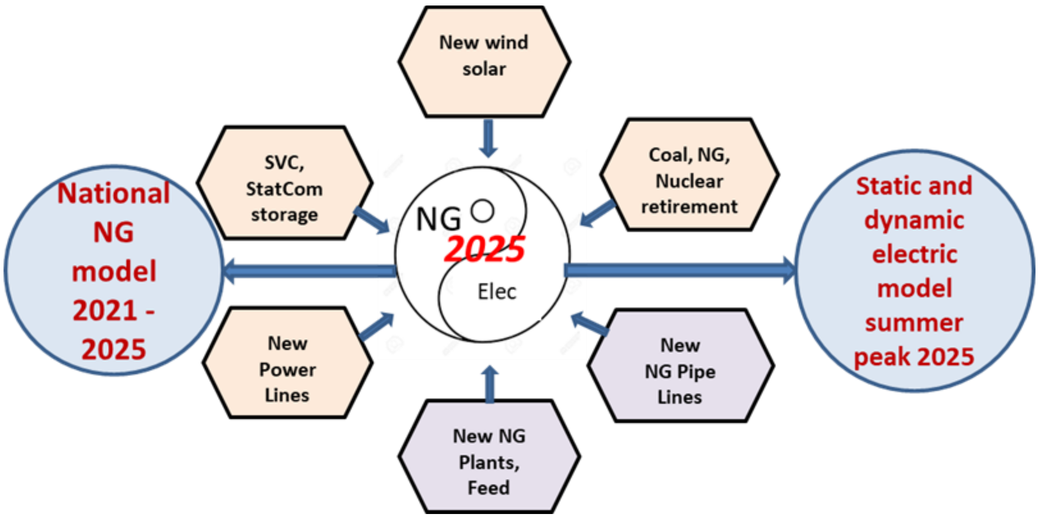


Figure ES-4. Interdependency of the Gas and Electric Cases into a Combined National Base Case

National Base Case Eastern Interconnect

Eastern Interconnect – Electric

Task Outline

This section provides a summary of the achievements for Task 3 of the NTRR project. The main focus is the base case development of the 2025 EI power grid. The major tasks completed by the team can be summarized as follows.

Task 3.1 – Development of the 2025 EI Summer Base Case

- Collected and compared information of generation additions and planned retirements from public data sources.
- Developed power flow model of 2025 EI Summer Base Case, reflecting Tier 1 capacity additions planned in the interconnection queues and confirmed retirements.
- Implemented transmission expansion and upgrades in the extended Pennsylvania Jersey Maryland (PJM) area.
- Developed dynamic models of the 2025 EI Summer Base Case.

Task 3.2 – Grid Strength Analysis

- Evaluated the impact of renewable generation on short circuit megavolt-ampere (MVA) level of the PJM area.
- Conducted voltage impact studies in Dominion Energy Virginia (DEV) area, using 70% composite load models.
- Identified potential weak grid issues and critical conventional generation plants for supporting grid strength.

Findings, Decisions, and Conclusions

The team has successfully developed the power flow and dynamic models for 2025 EI Summer Base Case. In addition, the team has also carried out grid strength analysis using the developed models. The study identified critical gas and coal plants in DEV area that are essential to maintain grid strength.

Development of the 2025 EI Summer Base Case

1. Based on recommendations from TRC and DOE, the team integrated Tier 1 capacity additions collected from generator interconnection queue of Independent System Operators (ISOs) and utilities in the 2025 EI Summer Base Case. Tier 1 capacity additions include projects that are under construction or have executed interconnection agreement (IA). Confirmed retirements sourced from EIA Form-860 [1] are used.

2. Power flow model of the 2025 EI Summer Base Case has been developed based on **2024 Multiregional Modeling Working Group (MMWG) Summer Peak case** by integrating Tier 1 capacity additions and confirmed retirements by the year of 2025. Capacity additions and retirements reflected in the 2025 EI Summer Base Case are shown in **Table ES-1**. The power deficit/surplus caused by new generation additions and retirements are balanced regionally by scaling up/down the power output of the in-service generators in the region. As a special case, DEV area provides a list of candidate generators that could have the priority to be taken offline to accommodate the new generation additions. This list is used to replace conventional generators with renewable generation in the DEV area.

3. Fuel composition of both on-peak capacity and nameplate capacity are calculated and shown in **Figure ES-5**. Capacity discount factors were considered in the on-peak capacity, as shown in the left pie chart.

Table ES-1. Capacity additions and retirements

Region	Renewable additions[1] (MW)	Gas additions[1] (MW)	Nuclear additions[1](MW)	Hydro additions[1](MW)	Coal retirements[1] (MW)	Gas/Oil Retirements[1](MW)
PJM	4540	8880	0	23	4408	0
SERC	5492	0	2200	0	991	332
SPP	2387	0	0	0	140	191
NPCC[2]	980	672	0	0	635	561
MISO	7859	0	-1457	119	17746	1527

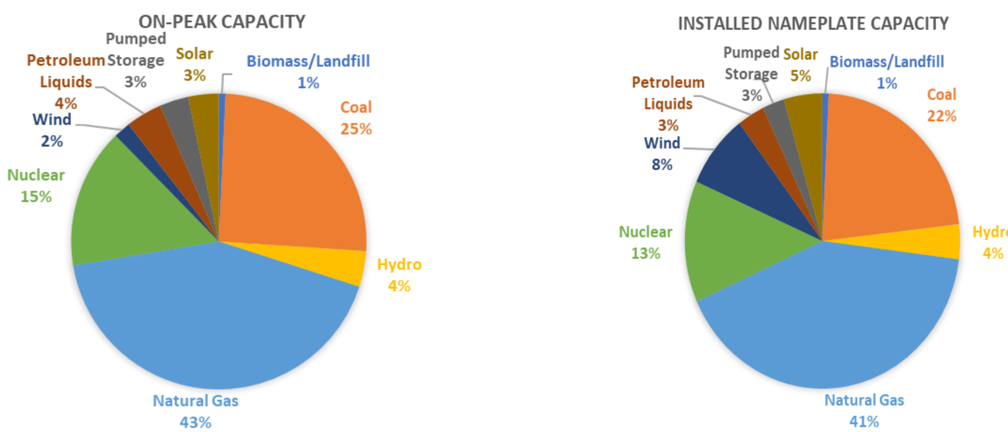


Figure ES-5. Fuel Composition of 2025 EI Summer Base Case

4. Forty-three baseline reliability projects of transmission expansion and upgrades within the extended PJM area are identified and implemented in the power flow model. In addition, ten new transmission line projects outside the extended PJM area are added to power flow model.

5. Confirmed retirements in Canada as mentioned in the NERC Long Term Reliability Assessment (LTRA) 2020 [2] report is modeled.

6. Based on the power flow model of 2025 EI Summer Base Case and 2024 MMWG dynamic model parameters, the team also developed the dynamic model. Generic parameters are used for new plants whenever necessary.

Grid Strength Analysis

1. The team has investigated system strength issues in the 2025 EI Summer Base Case, which could have a significant impact on the stable operation of inverter-based resources (IBRs). Grid strength is quantified at various locations in the 2025 case using short circuit ratio (SCR) based metrics [3], which are widely used in capturing system strength. Different metrics are applied in the 2025 case to identify potential weak areas where weak grid issues could arise.

2. As a proxy to grid strength, short circuit MVA (SCMVA) values are calculated at different voltage levels within the DEV area and results are compared between 2021 MMWG summer peak and 2025 Summer Base Case. The average SCMVA contribution from inside DEV area are shown in **Figure ES-6**. There is a decrease of SCMVA identified at buses over 115 kilovolt (KV) in the 2025 case, with a reduction of around 10% at 500kV. In addition, minimum SCMVA at different voltage levels are compared in the PJM area by regions, as shown in

3. **Figure** ES-7. Replacements of conventional machines with renewables result in a lower SCMVA level in some regions.

4. The team has conducted a study on the short circuit current contribution region. **Figure ES-8** shows the relationship between short circuit current contribution of different machines and their electrical distances to the short circuit location. It is identified that when the electrical distance from the short circuit location is greater than 1pu, the short circuit current contribution could be negligible.

5. The team has carried out voltage impact studies using the developed 2025 Summer Base Case. Composite load models are added for 70% of the total active power load within the DEV area. Bus voltages under balanced three phase fault conditions are simulated with different locations in the DEV area. Violations are identified using the NERC Protection and Control (PRC)-024-2 Standard [4] for generator ride-through capability, as shown in **Figure ES-9**(a).

6. Critical conventional generators within the DEV area are identified by comparing bus voltage responses after three phase-to-ground faults. The voltage drop during the voltage recovery period after replacing a specific conventional plant with renewables is selected as a metric for quantifying the importance of the plant. An example of the identified critical gas and coal generators is shown in **Figure ES-9**(b).

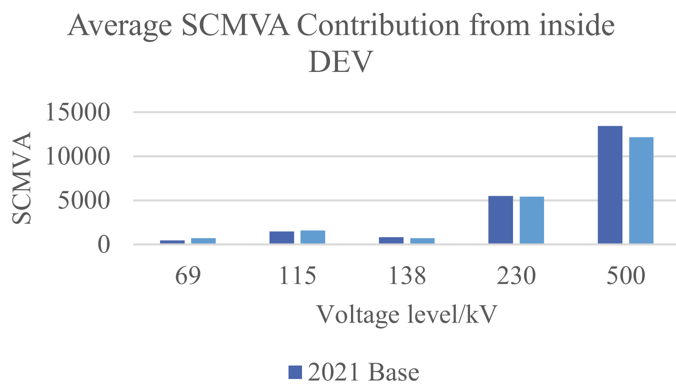


Figure ES-6. Average SCMVA comparison of DEV

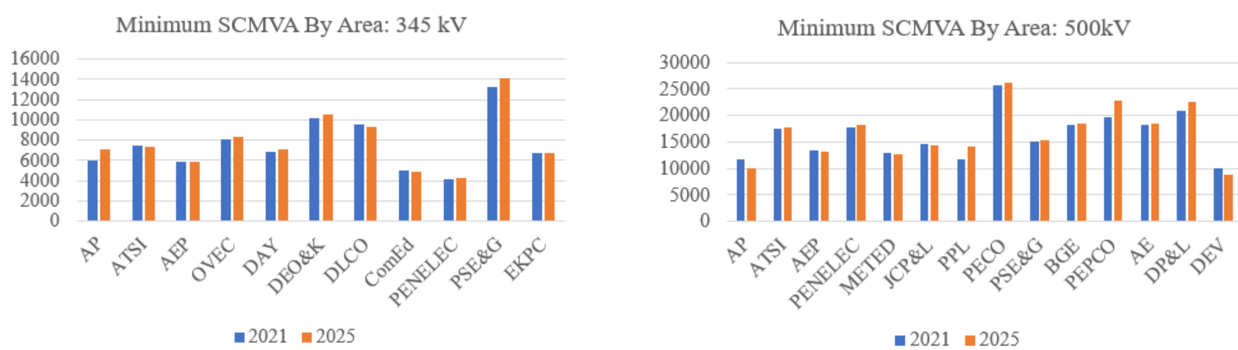


Figure ES-7. Minimum SCMVA of PJM by region

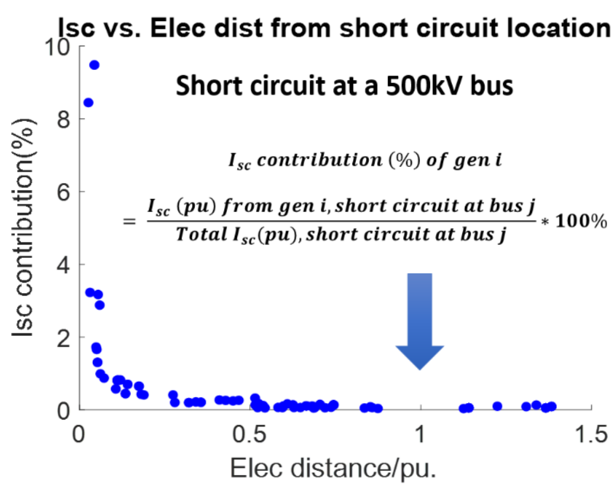
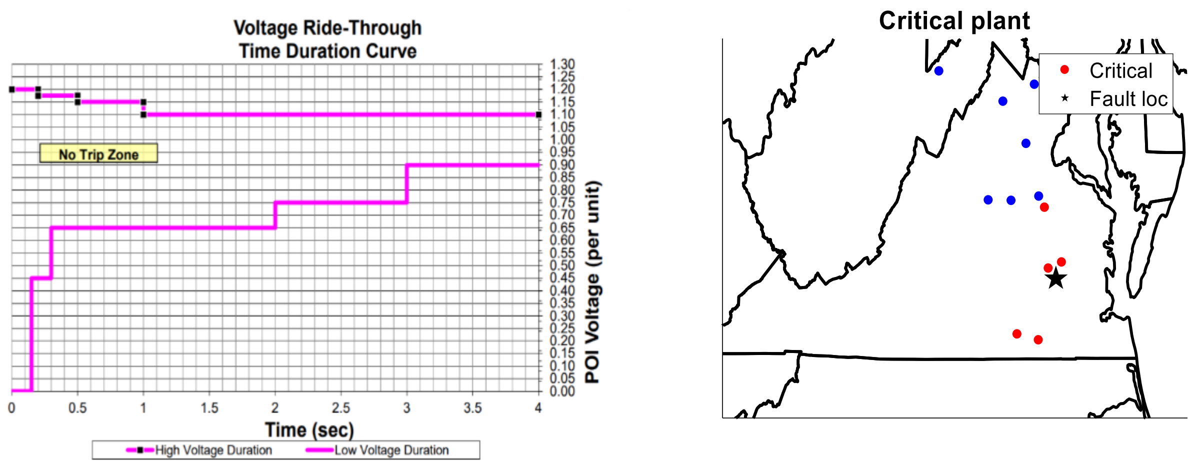


Figure ES-8. Short Circuit Current Contribution Region



(a) NERC PRC-024-2 generator ride-through capability

(b) Critical plant identification

Figure ES-9. Voltage impact studies

Eastern Interconnect Natural Gas

Accomplishments, Findings, Decisions, and Conclusions

The main focus is the development of a baseline of the interconnected national electric and natural gas sectors from 2022 to 2030. The major tasks completed by the National Energy Technology Laboratory (NETL)/ Argonne National Laboratory (ANL)team included in Task 3.0 in the Statement of Work (SOW) are summarized below. Work on this task is being performed utilizing electricity and natural gas system Critical Energy Infrastructure Information (CEII) along with other proprietary and restricted access datasets provided by other federal agencies and industry.

1. The inter lab gas team successfully developed a combined national electric and natural gas model for the US National Grid for the near term (the next 5 to 10 years). This model for electricity and natural gas covers the entirety of the interconnected North American natural gas network, and thusly the entirety of the three distinct North American power system interconnections since natural gas flows across regions and power sector demand in one interconnection can influence the gas supply and storage situation thereby affecting other regions.

2. The combined national electric and natural gas model spans an hourly temporal horizon from 2022 to 2030 to enable capture of full seasonal natural gas storage cycles, impacts of infrastructure changes in both the natural gas and electric systems, and representation of dynamics such as the diurnal nature of renewable energy systems, demand changes, and counterposed peak seasons for electricity demand (summer) and natural gas demand (winter).

3. NETL utilized the three commercial platforms: Hitachi Energy's PROMOD IV, an electricity system dispatch (production cost) model, Siemens Power System Simulator for Engineers (PSS/E), a transmission analysis software, and Deloitte's MarketBuilder, a generalized equilibrium model configured in this case for natural gas markets and infrastructure. ANL's NGFast model was used to evaluate potential natural gas delivery constraints for a scenario configuration of gas supply from production and storage, flows, and demands from storage and various sectors including gas-fired electricity unit dispatch.

4. PROMOD results for regional system local marginal price (LMPs) indicate that prices in WECC and California are predicted to rise in the summer months during the study period, reaching above $100 by 2030 (see **Figure ES-10**). These price increases during summer months are driven largely by

unmet load in California balancing areas. Prices in the summer months in ERCOT show a similar trend (**Figure ES-10**), driven by unmet load in the Houston load zone.

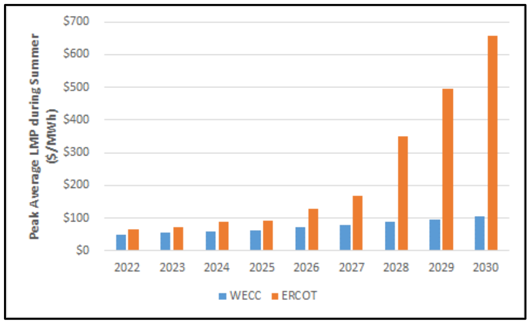


Figure ES-10. Regional Peak-Average LMPs during Summer Months for WECC and ERCOT

5. PROMOD results for electric generating capacity factor by generation type indicates nuclear, natural gas combined cycle (NGCC), and coal units will have the three highest capacity factors in each interconnect, with WECC showing increased capacity factors for other thermal generation, compared to the EI and ERCOT (see **Figure ES-11**).

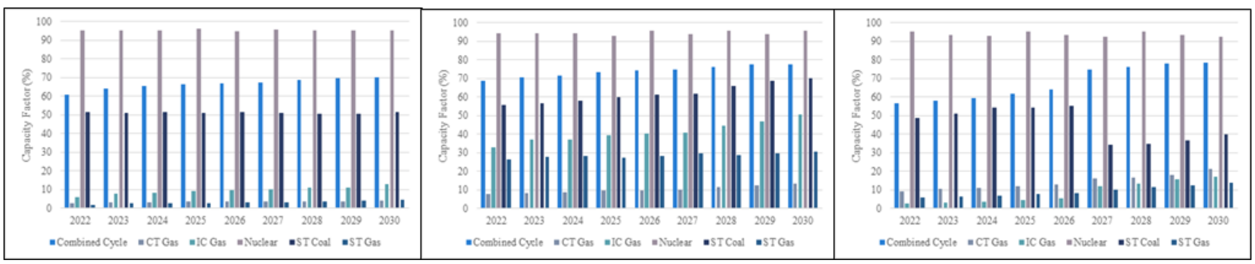


Figure ES-11. Capacity factors (%) by generation type for the Eastern Interconnect (left), WECC (middle) and ERCOT (right)

6. MarketBuilder was used to model the natural gas infrastructure from present day to 2030. Although the focus region is the expanded PJM territory, the national gas modeling included the Northeast, and that region remains the area within the country with the greatest natural gas deliverability challenges and consequently highest natural gas prices.

7. MarketBuilder results predict prices in the Northeast experience elevated prices in winter due to high seasonal demand and pipeline constraints in the region, even during normal winter weather conditions **Figure ES-12**). The results showed that as pipeline utilization approached 100 percent, the price to flow through the pipeline increased and the basis differential[1] across Northeast gas pipelines expanded.

[1] Basis differential is the price differential between the Henry Hub in Erath, Louisiana (the general benchmark) and the local cost of gas (the specific location).

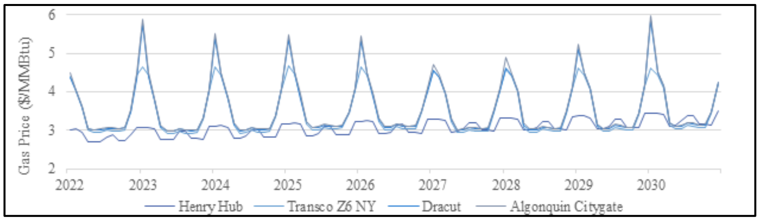


Figure ES-12. Northeast Natural Gas Hub Prices

8. MarketBuilder results showed that future prices in the Mid-Atlantic region (**Figure ES-13**) are not as high as in the Northeast, in part because of greater pipeline infrastructure capacity and also due to proximity to the large production areas of the Marcellus and Utica shale basins.

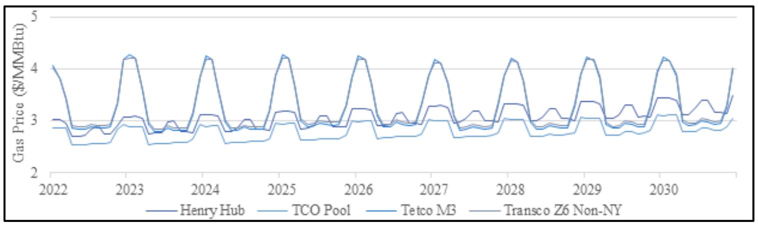


Figure ES-13. Mid-Atlantic Natural Gas Hub Prices

9. Natural gas prices at the Waha Hub (Texas) and Opal Hub (Wyoming) are lower than Henry Hub given the proximity to production areas (**Figure ES-14**). The discount at Opal to Henry Hub declines over time as production drifts to the Permian Basin and other areas over time. The demand hubs in California price at a premium to Henry Hub. Prices in both southern and northern California start with a strong winter price seasonality but starting in 2025, northern California exhibits a summer pricing peak, though at a lower level than the winter peak. This summer peak results from the retirement of the Diablo Canyon nuclear plant in northern California and the increased power sector gas demand to replace much of the lost output of the two nuclear units. Southern California gas prices also exhibit increased summer pricing, but to a lesser extent than northern California.

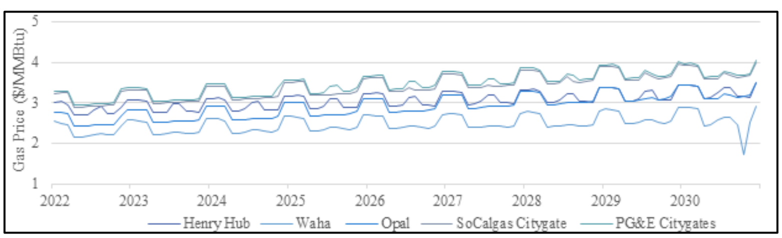


Figure ES-14. Western U.S. Natural Gas Hub Prices

10. NGfast validated the MarketBuilder results at each state and monthly period from 2022 to 2030 by ensuring Total Disposition (net storage changes plus extraction loss plus consumption) and Total Supply (marketed production plus net interstate movements plus net movements across U.S. borders plus supplemental gas supplies) balance in addition to ensuring maximum monthly-average daily gas pipeline flows predicted by MarketBuilder from 2022 to 2031 match future pipeline capacities when taking into account planned capacity expansions.

11. Monthly demand data by State and customer class (core, industrial, and electric power) predicted by MarketBuilder was downscaled by NGfast to the 1,600-plus individual local distribution companies (LDCs) and successfully compared with EIA annual gas company data.

12. A list of future gas-fired generators was developed using data from S&P Global Market Intelligence containing a total of 184 power plants – including 25 in Canada and 4 in Mexico (**Figure ES-15**). The status of future power plants was provided by NERC Tier. Connections of the future gas-fired generators to the gas infrastructure was based on current gas network, taking into account proximity to gas transmission pipeline(s) and comparison with gas connections with currently operating power plants. Power plants with large nameplate capacities were assumed to be supplied by transmission pipeline(s) with LDC connections assumed for smaller (up to 100 MW) gas-fired generators. The natural gas contracts and suppliers were also determined for future gas-fired generators.

Figure ES-15. Locations of Future Gas-Fired Generators in North America

National Base Case Western Interconnection

The National Renewable Energy Laboratory (NREL) team worked on building electric base case for the WI, and the focus is to develop credible chronological base cases. The WECC 2030 production cost model (PCM) retrieved in Dec. 2020 is the most updated reference model, therefore the WI electric base case for the year 2030 is built.

The WECC 2020 base case generation capacity and the projected 2030 generation capacity are compared in **Table ES-2** and **Figure ES-16**. As shown in **Table ES-2**, little change in thermal and hydro generation capacity is projected. The retired Coal-fire unit capacity is largely offset by the addition of Natural Gas unit capacity. The most significant changes in the generation capacity mix include the rapid growth in solar generation capacity and Distributed Energy Resource (DER) capacity.

Table ES-2. WI 2030 Generation Capacity Projection

Generation Type	2020 Base [GW]	2030 Forecast [GW]
Utility-Scale Solar	18	38
Wind Onshore	28	36
Hydro	73	68 (~55 Dispatchable)
Energy Storage (Pump & Battery)	1.9	10 (3.8 Pump Storage)
Distributed Energy Resources (DER)	8	28
Demand Response (DR)	NA	4.4
Thermal (Coal + Natural Gas + Nuclear)	148	142
Gen Capacity Total (excluding DR and DER)	269	**294**

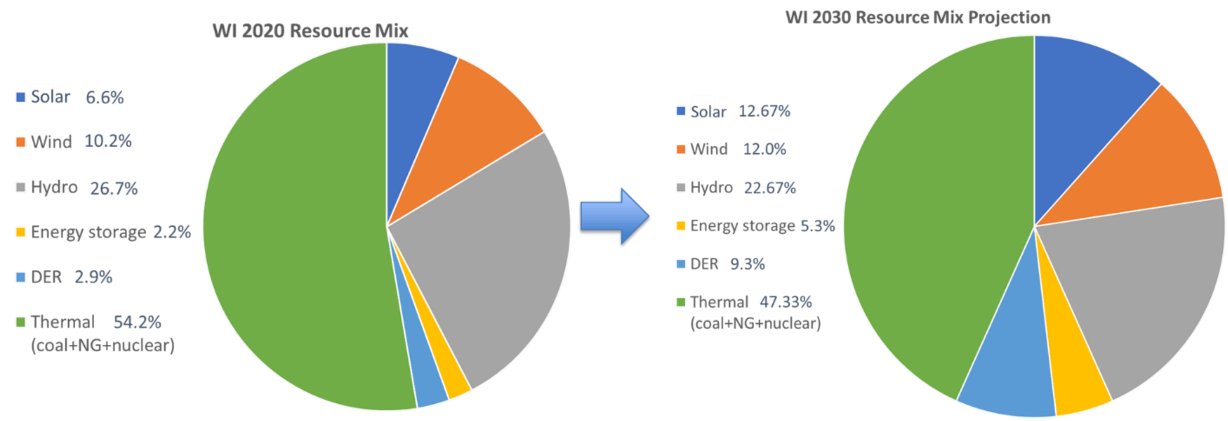


Figure ES-16. WI 2030 Resource Mix Projection

To build chronological WI electric base cases, assumptions associated with generation mix change and unit retirement are made, and detailed mapping was created to map WECC regional planning data to every individual bus using the WI energy management system (EMS) model. Two sets of base cases are created, one for heavy summer and one for heavy winter. Each set of base cases contains 24 hourly AC power flow snapshots. All AC power flows are validated and tuned to eliminate severe constraint violations. **Figure ES-17** shows the daily generation profile in WI 2030 heavy summer and heavy winter base cases. In WI 2030 heavy summer base case, the peak demand is 167 Gigawatt (GW). While in WI 2030 heavy winter base case, the peak demand is 134 GW.

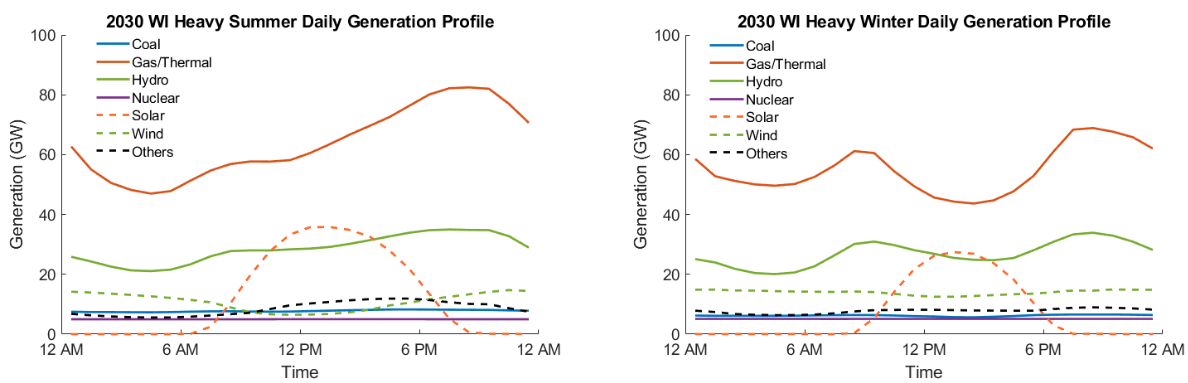


Figure ES-17. WI 2030 Heavy Summer and Heavy Winter Daily Generation Profile

The key findings of the WI 2030 electric base case are the change in the WECC path flow pattern and the growing risk in voltage stability, both caused by the change in the generation mix. The retirement of existing generators and the planned new generation, especially the increasing capacity of solar, reshapes the pattern and even reverse the direction of power flow on several critical WECC paths. We selected three key WECC paths to compare the impact of generation mix change. Path flow through path-65 at summer peak hours in WI 2030 is close to WI 2021 record because this path is a direct current (DC) intertie, and it is economic to utilize DC transmission capacity. However, the other two paths (path-26 and path-66) have very different path flow patterns at summer peak hours because of the high solar generation projection in California in 2030, resulting in reverse power flow on these paths. This significantly influences the effectiveness of existing grid operation protocols and lead to reliability and security concerns.

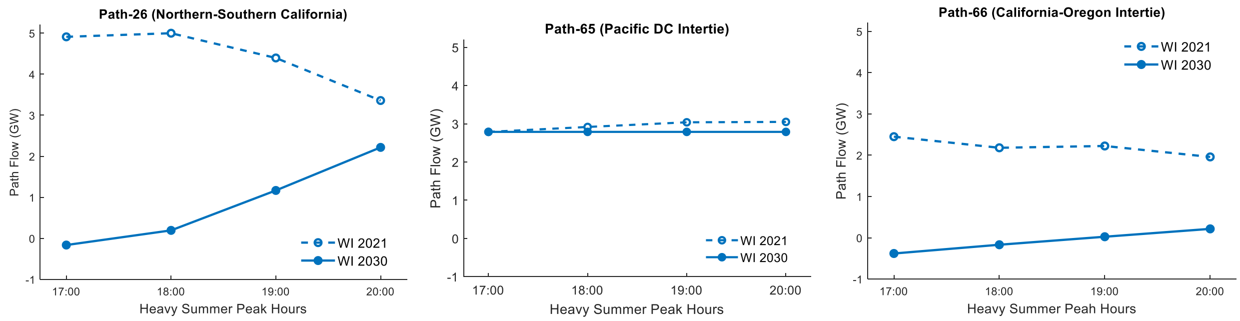


Figure ES-18. Change in WECC Path Flow Patterns

The voltage stability is analyzed using a simplified WECC model to evaluate the impact of uncertain renewable energy sources. The increasing renewable generation capacity enlarges the voltage magnitude variation and revealed the need to strengthen grid infrastructure for better voltage control to achieve the projected resource mix.

National Base Case – ERCOT

One of the largest challenges the NTRR Team faced in conducting the base case analysis was access to the ERCOT data and models. Access to this data is granted through the Federal Energy Regulatory Commission (FERC) and the CEII process. Throughout the project, the NTRR team, along with DOE, attempted to receive access to this data with no response from FERC. Thus, the analysis for the base case (and extreme cases (Tasks 4 and 5) focused on EI and WI.

Task 4: Extreme Weather & Cyber Impact in the East

Extreme Weather & Cyber Impact – Electric & Gas East

Task Outline

Extreme physical events, like wildfires, heatwaves, hurricanes, and earthquakes, and cyber events have historically caused stressful system conditions in three North American interconnections. The main focus is to evaluate reliability and resilience for extended PJM area in the eastern U.S., which includes PJM and Southeastern Electric Reliability Council (SERC) but excluding Florida, under extreme weather and cyber conditions with natural gas adequacy analysis. The major tasks completed by the team can be summarized as follows.

Task 4.1 – Collecting data and identifying the worst drought and winter storm case

- Collected historical weather, streamflow, power generation/consumption, and natural gas production/consumption data of extended PJM area.
- Identified the worst drought year and cold year by analyzing the historical weather data.
- Modeled scenarios with extreme drought followed by polar vortex in the PJM and SERC regions.

Task 4.2 – Impact of summer drought on natural gas and bulk power system in extended PJM

- Developed impact (capacity derating) model of hydroelectric and thermoelectric units during summer droughts.
- Developed impact (line ratings) model of transmission lines during summer droughts.

- Analyzed load forecast data of regular/extreme summer peak demand based on projection up to 2030 available at the PJM and SERC websites.
- Modeled the impact of extreme weather condition on load using temperature-humidity index (THI) during summer droughts.
- Analyzed the potential impact of summer drought on natural gas production and injection in the extended PJM service area.
- Analyzed the impact of summer drought on natural gas demand.

Task 4.3 – Impact of winter storm on natural gas and bulk power system in extended PJM

- Analyzed the forced outage rate (FOR) of conventional generators, including different type of units, based on historical outage rate data during winter storms.
- Analyzed historical FOR data of transmission lines from the PJM website and NERC reports/website.
- Modeled the impact of extreme weather condition on load using winter weather parameter (WWP) during winter storms for each load zone in the extended PJM area.
- Investigated the impact of winter storm on natural gas demand.
- Analyzed the impact of winter storm on pipeline operations and natural gas production.

Task 4.4 – Preliminary resource adequacy study

- Calculated usable capacity of at-risk thermal/hydro units in PJM/SERC region from 2007 to 2014 and found the worst drought year (2007) according to the calculated usable capacity.
- Conducted resource adequacy analysis to evaluate the amount of supply shortage if 2007 summer drought event strikes PJM/SERC power grid in near future.

Findings, Decisions, and Conclusion - Electric

The team has successfully developed the impact models on generation, transmission, and electric load during summer droughts and winter storms. In addition, the team has also carried out resource adequacy analysis using the developed models. Through the abovementioned tasks, the team provides the following findings, and conclusions:

Collecting data and identifying the worst drought and winter storm case

1. Data collected from the National Oceanic and Atmospheric Administration (NOAA) indicates that the average air temperature during summer period is around 86 °F in most states of the extended PJM area, and the maximum air temperature usually under 105 °F. United States Geological Survey (USGS) provides historical streamflow data of all states in the United States from 1930 to present. By analyzing the historical drought data, three severe drought years in the extended PJM area were 2002, 2007 and 2012. Polar vortex can affect Midwest, South Central, and East Coast regions of North American, and result in temperatures 20 to 35 °F below average. By analyzing the winter storm events in the past few decades, three severe cold years in the extended PJM area were 1989, 2014 and 2018.

2. Data collection from EIA 860 Form shows that, in extended PJM area, the total generation capacity is 424.8 GW as of 2021. The installed capacity of thermal, hydro, pumped storage, and wind/solar Photovoltaics (PV) is 377.38 GW, 13.78 GW, 11.8 GW, and 21.84 GW, respectively.

3. Data collected from PJM load forecast report (2021) and SERC Reliability Review Subcommittee (RRS) annual report indicate that there are 22 load zones in the PJM region and 13 load zones in the SERC region (excluding FL). In the next 10 years, the summer/winter peak load will keep increasing for almost all the sub-regions of the PJM region, and the annual growth rate of summer/winter peak load will be between 0.1% and 1.2%. The 2021-2030 demand forecast of SERC region shows a 0.62% compound annual growth rate (CAGR). Load growth is expected to be minimal across the central and southeastern SERC.

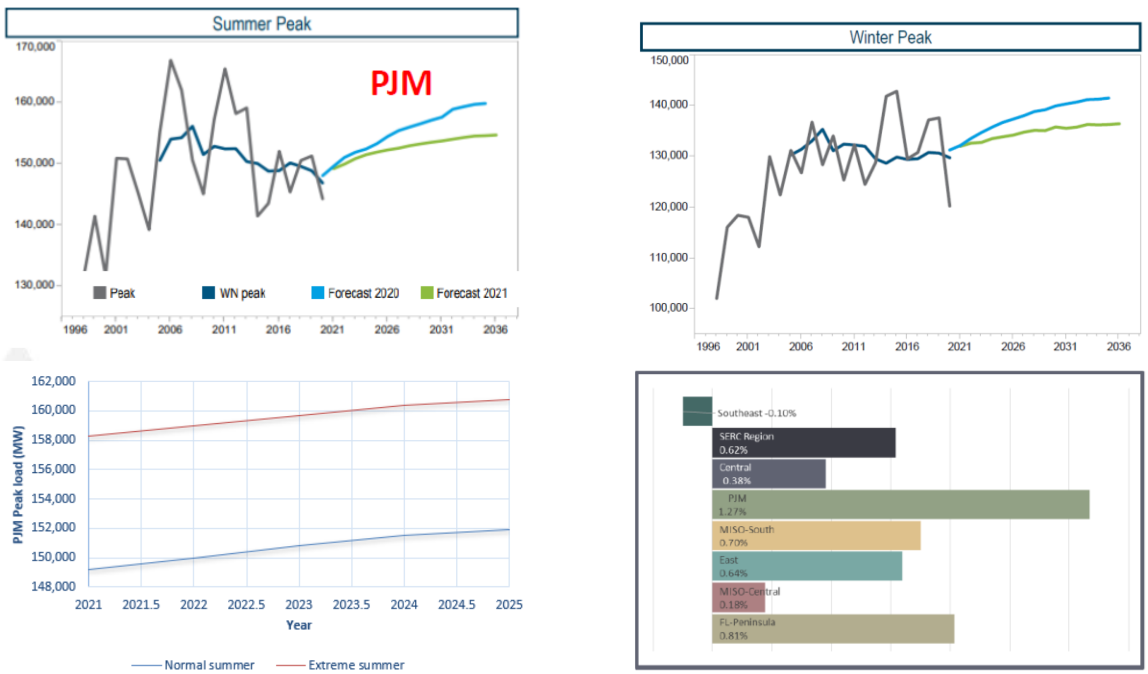


Figure ES-19. PJM and SERC load forecast

4. The team collected the following data sets in the extended PJM area: plant-level streamflow and water temperature data for the 133 at-risk thermal units with once-through cooling system; plant-level streamflow, water temperature, relatively humidity, and air temperature data for the 256 at-risk thermal units with recirculating cooling system; the historical air temperature data for the 2660 combustion turbine units; and the plant-level historical streamflow data for all hydro power plants.

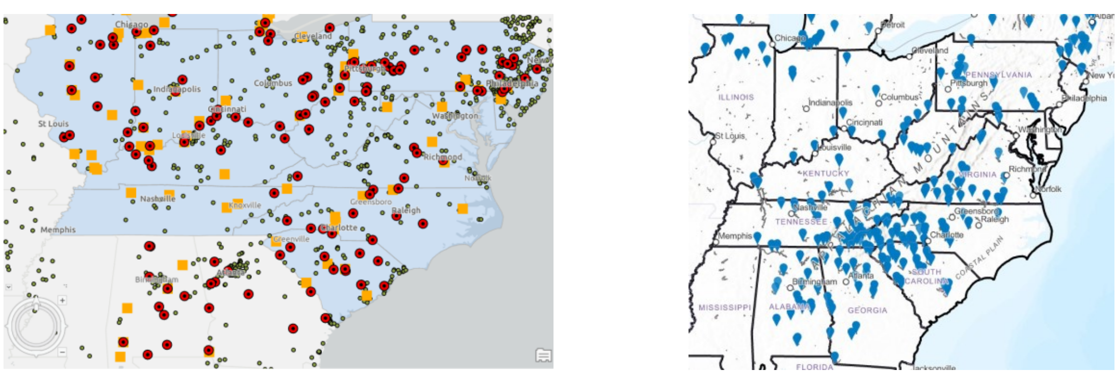


Figure ES-20. At-risk thermal plants and hydro plants in extended PJM area

5. Natural gas storage supplements natural gas production during periods of high demand. During the injection season, which is defined from April 1 to October 31, natural gas is typically injected into underground storage facilities from the interstate pipeline system; these facilities can be old natural gas wells or reservoirs no longer producing, salt caverns, or aquifers. Natural gas is then withdrawn from storage and delivered back into the pipeline network during the withdrawal season—November 1 to March 31—as needed to meet customer demand during the winter season. Decreases in electric transmission and electric generation capacity would increase reliance on fast-start gas-fired generation and hence underground gas storage which are used to provide gas supply on short notice, particularly in summer. The net effect would be a stronger reliance on underground gas storage in summer, and possibly increased gas use of stored gas. This would reduce the amount of gas injected during summer into underground gas storage and its availability during the upcoming winter months.

6. The team developed a credible summer drought scenario for the 2025 extended PJM model. The summer drought scenario is the historical case which occurred in the past during the summer drought event in 2007.

Impact of summer drought on natural gas and bulk power system in extended PJM

1. Thermal units using fresh surface water to cool systems are at-risk units. To accurately model the impact of summer drought on thermal power plants, the team formulated analytical models which evaluate the impact of weather condition on daily usable capacity of units by heat exchange equations. According to the heat balance of once-through cooling system, the usable capacity of the unit is affected by the available water flow, the maximum rise in cooling water temperature between the condenser inlet and outlet, regulatory limits of water discharged by a plant, thermal efficiency, etc. Also, the usable capacity of a unit with closed-cycle cooling system is affected by water temperature, air temperature, relative humidity, available water flow, etc. In addition, the usable capacity of a combustion turbine is affected by ambient air temperature. Past research works show that for every 1°C increases in ambient temperature above 15°C, the power capacity of a combustion turbine generator drops by about 0.7-1.0%. To validate the effectiveness of the analytical derating modeling methods, the team compared the calculated usable capacity and the actual power output of thermal units in the extended PJM area. The results show that the actual power output usually did not violate the calculated usable capacity, which validated the rationality and effectiveness of the derating models.

2. During summer droughts, the loss of hydro power generation is proportional to the loss of streamflow. The team collected the plant-level streamflow data and the hydro generation data, then calculated the daily usable capacity for each hydro plant in the extended PJM area according to the relationship between water flow and generator power output. And studied the correlations between hydroelectric generation and water flow during summer. The results show that the correlations are very strong.

3. By analyzing the rating data of transmission lines in PJM region, under different ambient air temperatures, transmission line rating decreases 0.5% per °C averagely when air temperature increases from 0 °C (32F) to 35 °C (95F).

4. The electric load has a very strong correlation with air temperature. The team collected the hourly load data and temperature data of PJM and SERC regions. To model the impact of temperature and humidity on electric load during summer, THI is utilized. By analyzing the relationship between THI and summer load for each load zone in the extended PJM grid, the team found that the correlations between THI and load value is very strong. Daily maximum load increases when the THI value goes up. At THI values less than 65, there are minimal load response to weather conditions. At THI values

around the high 70s or higher, there is often some moderation in load response from mid-range THI values.

5. During a long-term drought, natural gas-fired generation increases to compensate for curtailment of hydroelectric, nuclear, and coal-fired generation. **Figure ES-21** compares the daily gas demand for electric generation during 2007 and 2012 based on gas pipeline nominations data (nominations data is unavailable for 2002). Natural gas demand for electric generation increased significantly during the summer months of July to September 2007, which is not seen during 2012. The gas system was under greater stress during 2007, consistent with a hypothetical but plausible drought scenario impacting gas-fired generation in the combined PJM/SERC region.

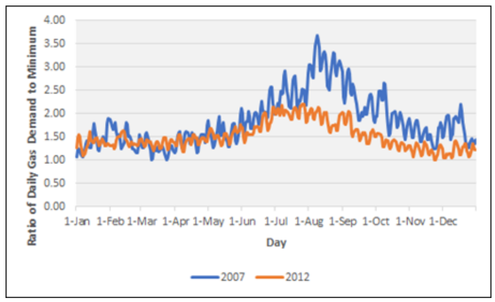


Figure ES-21. Comparison of Natural Gas Demand for Electric Generation for 2007 and 2012

6. Comparison of monthly gas injections during drought and normal conditions are conducted. **Figure ES-22** compares the monthly injections during the drought years of 2002, 2007, and 2012 with more typical conditions during 2003, 2008, and 2013. A similar monthly injection pattern occurs during normal conditions, with increased (nearly constant) injections during the months of May to September, which tapers off during the winter months. However, during drought conditions, monthly gas injections during the months of May to September are lower compared with normal conditions, reflecting the increase in gas demand for power generation. Then, the relationship between storage injections and demand for gas-fired electric generation is also studied.

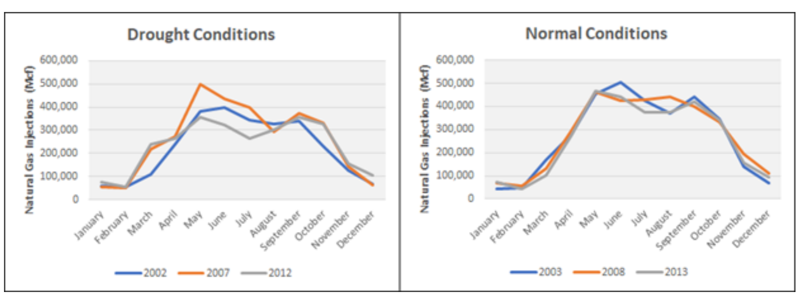


Figure ES-22. Comparison of Monthly Gas Injections during Drought and Normal Conditions

7. Drought conditions have the potential to affect natural gas production in the extended PJM service area. Water use for well stimulation by gas production basin has been collected and the impacts of drought conditions on future gas production were predicted based on the availability of water and the mean water requirements per well.

8. It is well-known that temperature has huge impact on gas consumption. The team investigated the relationship between daily average temperature against the daily total gas consumption as a function of state, based on interstate gas pipeline nomination data for 2019 and 2020. The results show that daily gas consumption always changes conversely against temperature.

Impact of winter storm on natural gas and bulk power system in extended PJM

1. The extremely cold weather results in high generator outage rate. According to the outage data from Generating Availability Data System (GADS), the historical winter monthly data during 2009-2014 in the extended PJM area shows that the Equivalent Forced Outage Rate (EFOR) performance of coal units ranged from 4.9% to 14.2%; the winter monthly EFOR of natural gas units ranged from 4.8% to 25.5%; the winter monthly EFOR of nuclear units ranged from 0% to 4.7%; the winter monthly EFOR of hydro/pumped storage units ranged from 0.9% to 10.4%.

2. The team also investigated the impact of weather conditions on transmission line outage rate and collected the element outage frequency, element outage duration, repair time, and up time for different voltage levels of transmission lines in the extended PJM area.

3. The team modeled the impact of temperature and wind speed on load during winter. The relationship between WWP and winter load is analyzed. We found that the correlations between WWP and load is very strong. When the WWP value is greater than 40, there appears to be minimal load response to weather conditions.

4. The team investigated whether dependence of daily natural gas demand with temperature may differ from State-averaged and LDC-averaged results. The assumption was the temperature dependence for LDCs would essentially match those for the entire State. Spot checks show this assumption is generally valid with some degree of deviation.

5. Extreme cold weather has a negative impact on gas pipeline equipment. The historical results indicate that the primary effect of extreme cold generally is the disruption of operations of one to two natural gas compressor stations located within the cold weather envelope. Another impact on pipelines is frost heave of the ground resulting in pipeline deformation, but the Department of Transportation (DOT) data indicates that pipeline breaks occur at a much lower rate.

6. Extreme cold weather can result in water produced together with natural gas forming ice-like hydrates that plug the valves coming out of gas wellheads (called well "freeze-off"). Daily natural gas production was dependent on the previous day minimum temperature (which seems reasonable since today's gas production depends on how cold was the previous day). Extreme cold weather impacts on natural gas production (examples shown in Figure ES-23Error! Reference source not found.) were investigated and possible constraints of on-site desiccant storage to continued gas production supply. Algorithms were developed correlating current day natural gas production with the previous day minimum temperature for individual counties in Ohio, Pennsylvania, and West Virginia.

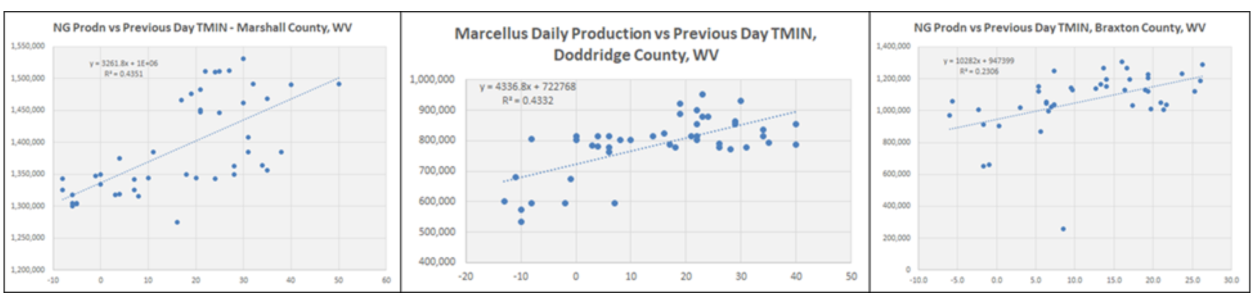


Figure ES-23. Example Extreme Cold Weather Impacts on Natural Gas Production

Resource Adequacy study

1. According to the 2021 generation mix data of PJM/SERC grid, the team used the developed capacity derating models to calculate the capacity reduction of PJM/SERC grid. The team found that the maximum generation capacity reduction of conventional generators will reach 50 GW if the 2007 summer drought event strikes PJM/SERC region in near future. The capacity reduction data during the summer drought event can be found in **Figure ES-24** and **Figure ES-25**.

2. Worst-case snapshot: The usable capacity is $351.8\text{GW} - 50\text{GW} = 301.8\text{ GW} < 302.1\text{ GW}$ (extreme summer peak load), which means the generation capacity is less than extreme summer peak load. This leads to supply shortage.

3. As the 2025 extreme summer case is more constrained than the resource adequacy analysis results shown above, we expect even more supply shortage and more load interruption.

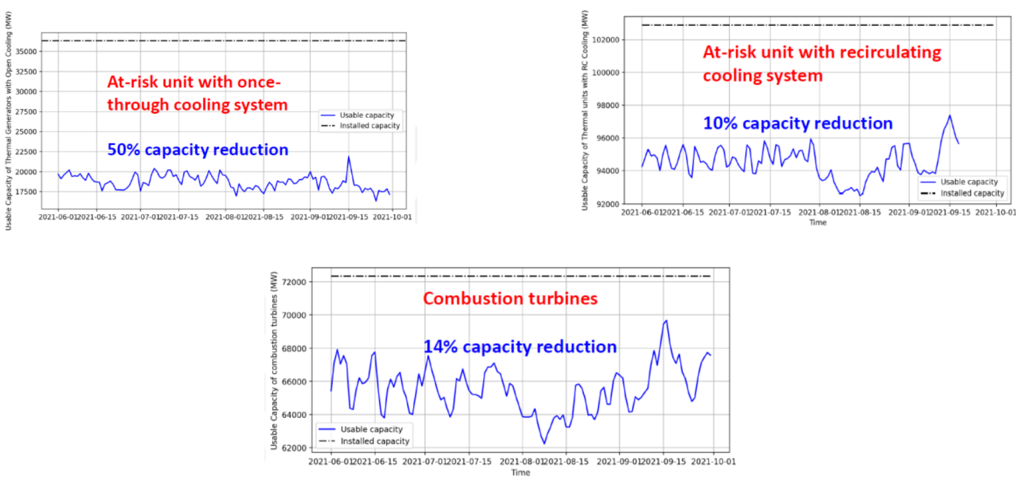


Figure ES-24. Total capacity reduction of at-risk thermal units with once-through cooling and recirculating cooling systems, and combustion turbines in PJM/SERC area (under 2007 summer drought condition)

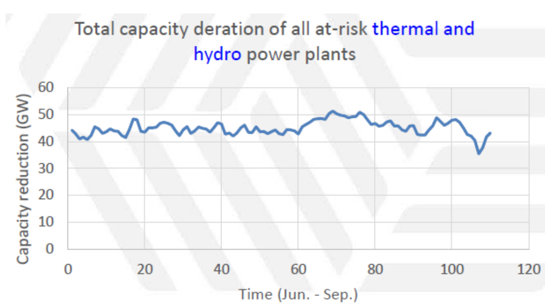


Figure ES-25. Total capacity reduction of all at-risk thermal units and hydro units in extended PJM area

Task 5: Extreme Weather & Cyber Impact in the West

Introduction

The focus of task 5 is the analysis of high-impact events on the 2025 WI power grid. Year one project efforts have been primarily preparatory, as full analysis depends on finalization and availability of the national base case models. Per initial project scoping, year 2 of phase 1 for the task 5 effort involved sensitivity analyses in the following dimensions: wildfire impact, natural gas price spike impacts, worst-case N-k continency impacts, and heat/drought impacts. Preparatory work and studies in support of the indicated year 2 sensitivity analyses were conducted, with key highlights as follows.

Accomplishments, Findings, Decisions, and Conclusions

Wildfire impacts are being considered on WI infrastructure, given recent historic events and projected intensification due to climate change. Wildfire data sources were secured via DOE's North American Energy Resilience (NAERM) model; Lawrence Livermore National Laboratory (LLNL) leads integration and development of NAERM wildfire capabilities. Two key sources of wildfire data are available: (1) active wildfire perimeters for the continental United States (CONUS), obtained from the National Interagency Fire Center (NIFC); and (2) forecasted areas of wildfire ignition and spread within the state of California [84]. Both the active and forecasted wildfire data were analyzed for the 2021 wildfire season, specifically focusing on bulk electric and natural gas infrastructure impacts. Impactful historical wildfires on both electricity and natural gas infrastructure have been identified, as have likely additional areas of high risk to wildfire impacts.

Either due to global events or market forces, the impact of natural gas price spikes on power system production and operations cost is also of significant concern to both system operators and more broadly. Toward enabling such analyses on the WI, a study framework was developed for analyzing the impact of natural gas price spikes on resulting dispatch stacks. The experiments were conducted using the open-source Prescient PCM tool, available from: https://github.com/grid-parity-exchange/Prescient. The study was conducted on a high-share renewables PCM case known as reliability test system (RTS)- Grid Modernization Laboratory Consortium (GMLC), available from https://github.com/GridMod/RTS-GMLC and developed previously under DOE/GMLC funding. The analytic focus of this study was on changes in the dispatch stack, energy prices, and generator profitability. Parametric analyses indicate that substantial changes in NG prices can have a significant impact on both dispatch stacks and system costs.

Worst-case N-k contingency analysis is being conducted to address "all-hazard" impacts associated with concurrent failures of multiple grid components, e.g., k >> 1. The source of component failures is intended to be agnostic to cause, e.g., cyber vs. physical and intentional vs. accidental/natural. Codes developed by LLNL for DOE's NAERM effort, specifically the Intentional Threat Toolkit, were executed on WECC 2018 and 2020 planning cases, to identify high-impact contingencies for k ranging from 2 to 20. These contingencies were then simulated using transient power flow simulators, to determine cascading impacts and quantify overall impacts. Several severe events were identified starting with a contingency "budget" (the number of outaged components) of k=4, with impacts – quantified as both the load lost and number of subsequently outaged components) growing substantially with larger values. Results for worst-case N-k contingencies that yield high impacts in the WI are necessarily sensitive, in that they identify critical grid component. Consequently, the details of the contingencies and the extent of the impacts are not reportable in an open forum.

Mirroring efforts conducted under task 4 for the EI, drought and heat analyses are a key sensitivity planned for WI analysis. To establish a process for analyzing and quantifying impacts on the WI due to drought and heat, sensitivity analyses were conducted using the GridView PCM tool, considering the WECC 2030 v2.0 case (obtained under standard non-disclosure agreement (NDA) with WECC). Code infrastructure to support automatic updating of large numbers of line ratings were developed and tested. Here, we see relatively minor impacts in terms of system reliability and costs, despite a modest reduction in overall transmission capacity limits. Analyses should be considered by DOE, leveraging WECC internal PCM models focusing on wildfire and heat impacts analysis.

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1. Introduction

The Near-Term Reliability and Resiliency (NTRR) was awarded in December 2020 as an inter-lab project to examine the reliability and resilience of the electricity grid and natural gas transportation availability. The project builds on studies conducted by The North American Electric Reliability Corporation (NERC), the U.S. Department of Energy (DOE), and other non-governmental research and operational focused on reliability and resilience analyses challenges. The research was conceived to address near-term scenarios (within 10 years), when many local and regional policy transitions could begin to impact grid reliability, resilience, and supporting infrastructure availability.

Inputs from the validated PSS/e cases in the East and PSLF case in the West were used for building the electric base case. This development used information from NERC, PJM, Western Electricity Coordinating Council (WECC), state renewable portfolio standards (RPS), and the Energy Information Administration (EIA) resource mix projections for 2025 to develop a credible base case for each interconnection. The comprehensive national base case does include coal, gas, and nuclear retirement in all regions from industry determined list and EIA/NERC projections. In order to be as realistic as possible, the project team leveraged the industry-developed 5-year-outlook models such as Multiregional Modeling Working Group (MMWG) 2025 and WECC 2025 load flow base cases. To integrate the natural gas interdependency the team began with the generating capacity and demand projections from the 2020 NERC Long-Term Reliability Assessment (LTRA) and the Bulk Electric System (BES) transmission topologies defined in the WECC Anchor Data Set, Eastern Interconnection Reliability Assessment Group Multi-Regional Modeling Working Group (ERAG/MMWG) Data Set, the team calculated baseline regional power sector gas demands from present electricity delivery year through the end of delivery year 2030/31 by applying security constrained economic dispatch. This demand was compiled along with demand projections for regional residential, commercial, and industrial natural gas demands from the most recent EIA Annual Energy Outlook Reference Case into Deloitte's MarketBuilder® North American Gas Model. Through the application of these demands, MarketBuilder® was projected the topology of natural gas flows in the natural gas pipeline network across the interconnected North American system along with regional natural gas prices that will be seen by market participants in future years. With interconnect wide base cases developed the team can now address extreme events within each interconnect.)

Additionally, contingencies and sensitivities focused on the built models of the Eastern Interconnection (EI) and Western Interconnection (WI). They addressed challenges from the following with the outcomes being an identification of performance under the extreme conditions and an identification of potential grid weaknesses that should be addressed to mitigate the reduced performance and improve the resilience and reliability of the specific regions as well as the National Grid:

- Weather events including extreme heat, extreme cold, high wind, no wind, wind and solar forecasting errors, and wildfires.
- Gas availability, factoring in supply disruption (contractual and physical), seasonal availability constraints, and infrastructure limitations; and
- Transmission availability and congestion.

1.1 Project Structure

Figure 1-1 shows the high level NTRR project organization.

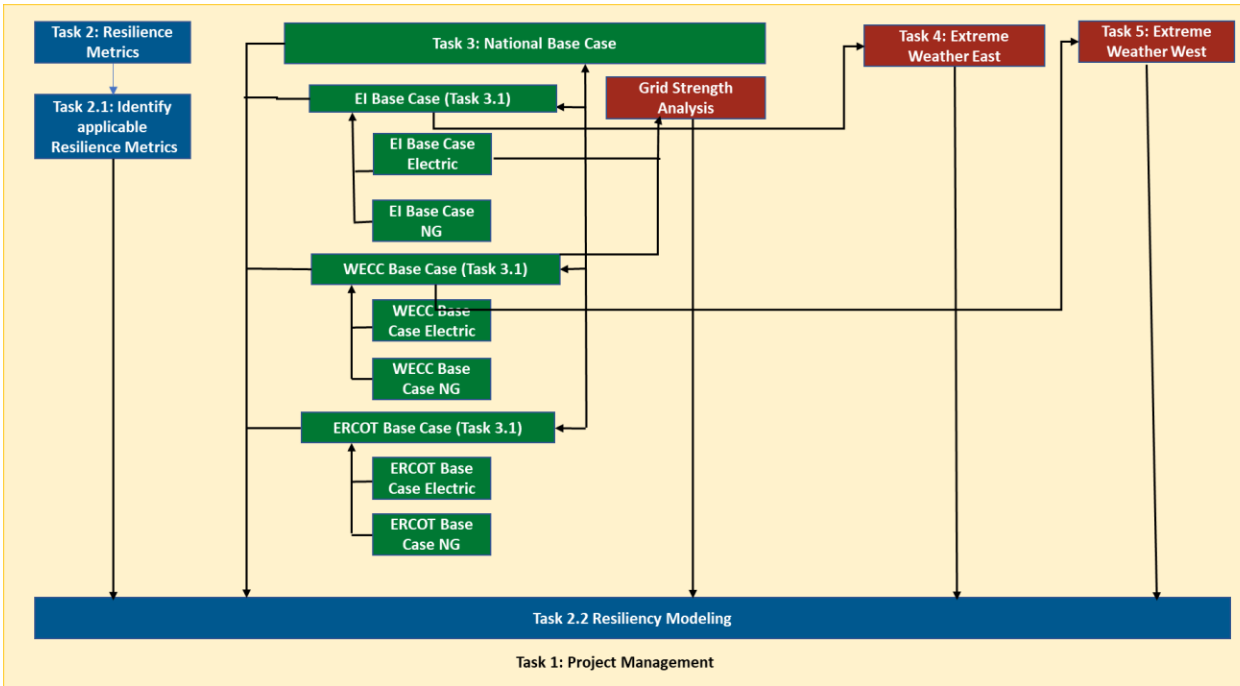


Figure 1-1. NTRR Project Structure and Task Relationships.

1.2 Project Challenges and Misconceptions

The challenge in analyzing the Near-Term reliability and resilience of the electric grid form a national level is the assumption that the United States has a national electric grid. This assumption is not completely accurate. The electric transmission grid within the United States consists of three (3) Interconnections EI, WI, and The Electric Reliability Council of Texas (ERCOT) Interconnect that operate like semi-independent transmission grids that are loosely connected through both alternating current (AC) and High Voltage Direct Current (HVDC) connections. Additionally, the EI and WI grids are a synchronized grid (same grid frequency), but the ERCOT interconnect is asynchronous (different grid frequency) to both EI and WI interconnects under normal system conditions. Adding to the complexity of analyzing the near – term reliability and resilience from a national level is an underlying natural gas (NG) infrastructure that provides fuel to the natural gas generators. This infrastructure is a well-integrated system of pipelines for "transporting NG" throughout the U.S. This NG infrastructure also faces reliability and resilience challenges such as frozen compressors and inability to pump NG to the generators, thus causing a derating or lessening of the ability of a generator to provide the necessary power to the grid.

This misconception or misunderstanding leads many, even within the industry, to assume that there is a single grid that can mutually assist during normal operations and under extreme conditions. The actual ability for one "region" to support another is limited to the ability to use the few interconnections that exist between the regions. **Figure 1-2** shows EI, WI, and ERCOT and the associated interconnections.

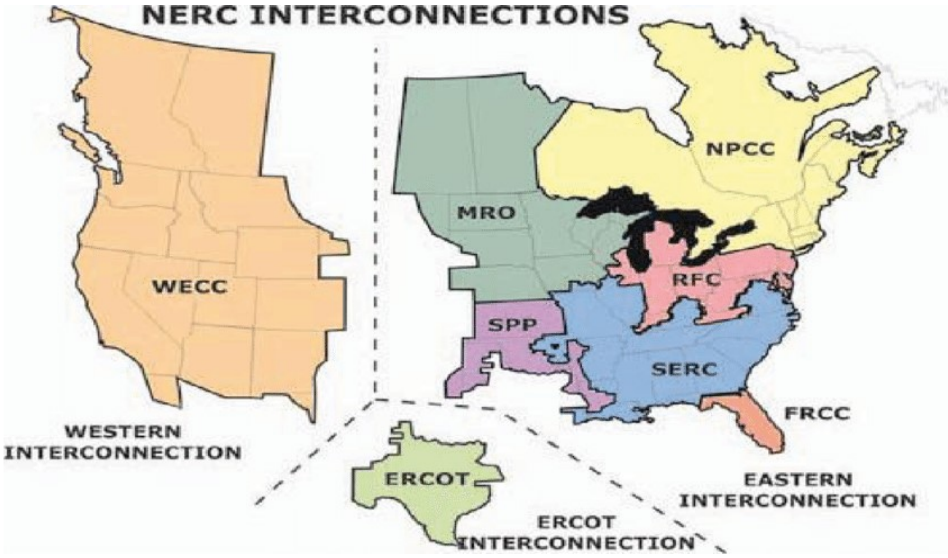


Figure 1-2. National Electric Grid- Three Loosely Connected Regions

1.3 NTRR Report Purpose and Structure

1.3.1 Report Purpose

As the NTRR project closes, this report summarizes the accomplishments made relative to the project scope and objectives.

1.3.2 Report Structure

The NTRR Final Report is organized along the lines of the tasks. Each major Task (listed below) is divided into the components (subtasks) and for each component, the report contains:

- Section 1: Introduction – Includes project scope, overview, purpose, and challenges.
- Section 2. Task 2: Resiliency Metrics for the Electric Grid and Natural Gas System - Definition and description of resiliency metrics developed to evaluate grid reliability and resilience.
- Section 3. Task 3: National Base Case development and analysis / finding for the national base case for EI, WI, and, and ERCOT. These were analyzed somewhat separately as the three regions are loosely connected grids, U.S. does not operate a singular "national" grid.
- Section 4. Task 4: Extreme Weather & Cyber Impact in the East.
- Section 5. Task 5 - Extreme Weather & Cyber Impact in the West.

2. Task 2: Resiliency Metrics for the Electric Grid and Natural Gas System

This section presents the metrics that the NTRR project employed in its studies of the impact that the electric and gas infrastructures have on each other, especially under very challenging conditions. These metrics were be used to evaluate the reliability and resilience of the electric grid and natural gas system in near-term scenarios (within the next 10 years) that involve extreme weather events and significant supply disruptions to both electric and gas availability. The report defines the metrics, describes how they are calculated, and the process by which the metrics are used to evaluate the reliability and resilience properties of the simulated scenarios. The report also shows how the resilience metrics play into the other tasks of the project. Finally, the report provides a summary of the software tools that were deployed to calculate and visualize the metrics.

The primary purpose of Task 2 is to be an enabler of apples-to-apples comparison of grid resilience and reliability across electrical interconnections, across the natural gas infrastructure, and across the spectrum of scenarios to show a full national resilience picture. To do this, Task 2 incorporated the results of the other tasks to perform the resilience analysis.

This task identified and described the different reliability and resilience metrics used in the NTRR project. The metrics consist of both quantifiable metrics and probabilistic metrics.

- Quantifiable Deterministic Metrics (Grid Reliability and Grid Resilience):
  - **Static security assessment** - Static security assessment determines whether a power system is able to supply peak demand after one or more pieces of equipment (such as a line or a transformer) are disconnected.
  - **Dynamic security assessment** – Dynamic security assessment checks whether a system will reach a steady state after a fault occurs.
- Probabilistic Metrics - Probabilistic criteria such as Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS) address the concerns that contingency criteria does not consider the probability of a contingency occurring or its impact should it occur.
  - **System Adequacy** - System adequacy assessment is probabilistic in nature. Each component of the system has a probability of being available, a probability of being available with a reduced capacity, and a probability of being unavailable. To assess the transmission reliability, it is assumed that the generation is sufficient and the distribution systems serving the loads are operated appropriately. This allows the probability of all transmission state combinations to be computed.

2.1 Introduction

In the near future, many local and regional policy transitions could begin to impact the reliability and resilience of the electric grid. The NTRR project studies and addresses such scenarios to determine what challenges exist. The project focuses on the operation of the power system using existing projections for electricity demand as well as infrastructure, pricing, and gas production from the EIA and other appropriate sources. In an effort to examine the reliability and resilience of the electric grid and natural gas transportation availability, this report identifies and describes the specific reliability and resilience metrics that were used in the NTRR project.

Power system reliability refers to the ability to maintain the delivery of electrical power to customers in the face of routine uncertainty in operating conditions [1]. Reliability is defined by the NERC as the degree of performance of the elements in the BES that results in electricity being delivered to customers within accepted standards and in the amount desired [2]. Reliability of the electric power system focuses on assuring adequate grid operations in typical conditions, through a real-time balancing of load and generation, operating within defined limits, and adequate operator training [1]. Reliability involves the performance of the electric grid against high probability, low consequence events.

On the other hand, resilience involves the performance of the grid due to low probability, high consequence events such as hurricanes, earthquakes, and man-made threats. Resilience refers to the ability of the grid to prepare for and adapt to changing conditions, withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents [3].

The future grid reliability and resilience investigations should cover a balanced portfolio of all aspects of the bulk power system (BPS) from generation through end-use, e.g., transmission, generation, and demand [4]. Thermal generating units are the foundation of the grid, but due to renewable portfolios, decarbonization goals and cost competitiveness, the future of these generation units is in doubt. To compare generation units, capacity factors and marginal operating factors are the two metrics used in the literature for gas, coal, and nuclear power plants.

Natural gas is currently the fastest-growing source of electric power generation, according to data from the EIA Hourly Electric Grid Monitor. The increase in natural gas-fired generation was the result of recent low prices and natural gas-fired power capacity additions. Natural gas-fired generation has generally increased in most U.S. regions since 2015, according to data from the EIA Power Plant Operations Report. Annual electricity generation from natural gas power plants in the United States increased by 31% in the Northeast region, by 20% in the Central region, and by 17% in the South region between 2015 and 2019. In the West region of the continental United States, electric power generation from natural gas power plants remained relatively flat during the same period.

In 2019, 40% of the natural gas delivered by transmission and distribution pipelines went to electric power plants, 30% to industrial plants, and 30% to residential and commercial consumers. Gas transmission reliability is an important factor to gas generation units and distribution reliability should be analyzed for residential and commercial consumers. The distribution and transmission of gas pipelines are subject to different regulations which affected reliability analyses. In this document, generation reliability and resilience are discussed.

Modeling the resilience of natural gas is necessary to understand its risks and its contribution to grid infrastructure improvement decisions to make it less vulnerable to weather-related outages and reduce the time it takes to restore power after an outage. The integrated electricity and natural gas analysis with the proposed methods and metrics is aimed at improving the resilience of the power grid.

2.1.1 Reliability vs Resilience

A main differentiator between reliability and resilience is the frequency and impact of an event. Reliability focuses on assuring adequate grid operations in typical conditions, through real-time load and generator balancing, and operating equipment within defined limits. Resilience focuses on the operation of the grid during extreme and adverse events, which can be categorized as atypical and emergent conditions. Another distinction between reliability and resilience is that a system may be considered reliable without identifying a specific threat to the system. However, when discussing resilience, systems are considered resilient to a particular threat or set of threats. Hence, reliability metrics do not attribute the cause to the metric (e.g., a load is de-energized without regard to why or how), whereas resilience metrics do consider the cause (e.g., a hurricane caused the load to be de-energized). Therefore, resilience bridges the gap between the system response and a root cause.

2.2 Time-Dependent Analysis of an Event

An important aspect of resilience is its time-varying nature. Many of the basic elements of system resilience can be captured in different phases before and during a severe event as well as after the event, when the system has been restored. **Figure 2-1** shows an illustrative generic resilience curve where a resilience indicator is used to quantify the resilience level of a power system during an event as a function of time. The resilience indicators are in the form of the following:

- The amount of generation capacity (MW).
- The load demand served or not served (MW).
- Number of transmission lines tripped.
- Number of outages.
- Number of customers not served.

In **Figure 2-1**, five different phases can be clearly seen: the pre-disturbance state, disturbance state, post-disturbance degraded state, recovery & restoration state, and the post-restoration state.

2.2.1 Pre-disturbance Phase:

The pre-disturbance state is the operating point of the system before a severe event occurs. In this state, resources are prepositioned to prepare for an event. Remedial actions are set up to minimize the impact of the event. The metrics that are calculated in this phase include Loss of Load Probability, Planning Reserve Margins, etc. These metrics quantify the generation resource adequacy.

2.2.2 Disturbance Phase

The disturbance phase is the time between the start of the event to the end of the event. In this phase, the resilience indicator quantifies how fast and how low the resilience drops. This includes the amount of generation MW lost, load MW disconnected, and the rate at which generation, transmission lines, and customers are disconnected during the event.

2.2.3 Post-Disturbance and Degraded Phase

Following the end of the event and just before restoration is initiated is the post-disturbance degraded state. In this stage, the damages caused by the event are assessed and critical components required for recovery are identified.

2.2.4 Recovery and Restoration phase

A resilient system should demonstrate high restorative capabilities in order to restore disconnected customers and collapsed infrastructures. The recovery phase of the event commences at the time the system performance has reached its minimum level and ends at a point in time in which some minimally acceptable and stable level of system performance has been recovered through adaptive actions by the system and its human operators.

2.2.5 Post-Restoration Phase

Following the event and the restoration of the system to an acceptable operational state, the post-restoration phase begins. In this phase, the impact of the event and the performance of the network are thoroughly analyzed to identify the weaknesses and limitations of the network.

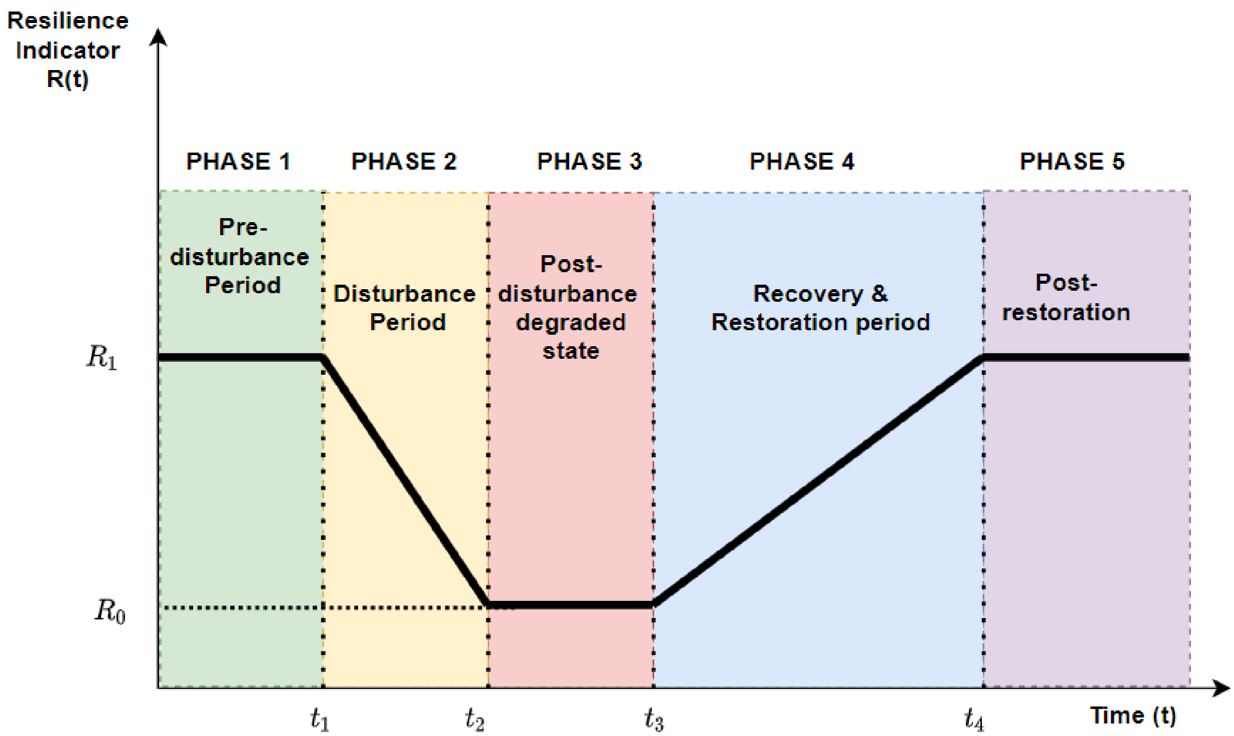


Figure 2-1. Multiphase Trapezoid Curve

2.3 Resilience Metrics

1. FLEP Metric Set.
2. Severity Risk Index.
3. Dynamic Resilience Indicator.
4. Weighted Short Circuit Ratio.
5. Cumulative customer energy demand not served.
6. Critical customer energy demand not served/ Critical services without power.
7. Time to operational recovery.
8. Time to infrastructure recovery.

2.3.1 FLEP Metric Set

The FLEP metrics [5] is a time-dependent resilience metric set that captures the performance of a network during the different phases associated with an event. It includes how Fast (Φ) resilience drops, how Low (Λ) resilience drops, how Extensive (E) the post-degraded state becomes and how Promptly (Π) the network recovers to its pre-event state [5]. **Table 2-1** summarizes the FLEP (ΦΛΕΠ) metric set.

Table 2-1. FLEP Metrics Set.

Phase	State	Description	Symbol
1	Disturbance Progress	How fast resilience drops	Φ
2	Disturbance Progress	How low resilience drops	Λ
3	Post-disturbance degraded state	How extensive is the post-disturbance degraded state	Ε
4	Recovery and Restoration state	How promptly does the network recover	Π

Table 2-2 shows the mathematical representation of the FLEP metric set, The Φ-*metric* is evaluated by estimating the slope of the resilience curve during the disturbance phase, while the Λ-*metric* is defined by the resilience degradation level at the end of the event at t_2. The *E-metric* is simply the time that the network remains in the *post-disturbance degraded state* is given by $t_3 - t_2$. The Π-metric is defined by the slope of the resilience recovery curve which considers both the resilience improvement during this phase and the time required for achieving this required for reaching this resilience level [6]. Complementing the "ΦΛΕΠ" resilience metrics system, an additional metric can be used, i.e., the *area* of the trapezoid. The *area* metric is expressed as the integral of the trapezoid for the duration of the event.

Table 2-2. Mathematical representation of the FLEP Metric set.

Metric	Mathematical Expression	Unit
Φ	$\frac{R_0 - R_1}{t_2 - t_1}$	MW/hours, No. of lines tripped/hours, No. outages/hours, No. of unserved customers/hours
Λ	$R_1 - R_0$	MW, No. of Lines tripped, No. of outages, No. of unserved customers
E	$t_3 - t_2$	Hours
Π	$\frac{R_1 - R_0}{t_4 - t_3}$	MW/Hours, No. of lines restored/hours, No. of restored customers/hours
Area	$\int_{t_1}^{t_4} R(t)dt$	MW X hours, No. of lines in service X hours, No. of outages X hours, No. of customers X hours

2.3.2 Severity Risk index (SRI)

The SRI is a metric where generation loss, transmission loss and load loss events are aggregated into a single value that represents the risk to the Bulk Energy System. It can serve as a resilience indicator of the power system over a longer period. The score can show the best and poorest performance of the grid within weeks, months, or a year.

As shown in **Figure 2-2**, the SRI is the sum of three weighted components: percentage of generation lost, percentage of transmission lines tripped, and the percentage of load disconnected. To calculate the SRI, each element (generation, transmission, and load loss) is weighted by a pre-determined factor. It can be written as:

$$SRI = \beta_1 G + \beta_2 T + \beta_3 L$$
$$\beta_1 + \beta_2 + \beta_3 = 1$$

Where G is the percentage of Generation lost per hour/day, T is the percentage of Transmission lines tripped per hour/day, L is the percentage of load disconnected per hour/day, β_1, β_2, and β_3 are the weighting indices. NERC calculates a daily SRI for the BES with $\beta_1 = 0.1, \beta_2 = 0.3$ and $\beta_3 = 0.6$

2.3.3 Dynamic Resilience Indicator (DRI)

The NTRR team with the TRC developed the DRI to address the need for an overall resilience measure for shorter periods, e.g., minutes to hours. As shown in **Figure 2-2**, the DRI is also the sum of three weighted components:

- RR: The measure of reactive reserves, e.g., the phase angle separation between areas/regions of interest.
- LL: the Loadability limit, e.g., the point of maximum load, i.e., the tip of the nose curve.
- FA: Measure of frequency agility e.g., the percentage of frequency nadir.

Mathematically, the DRI is written as:

$$DRI = \alpha_1 RR + \alpha_2 LL + \alpha_3 FA$$
$$\alpha_1 + \alpha_2 + \alpha_3 = 1$$

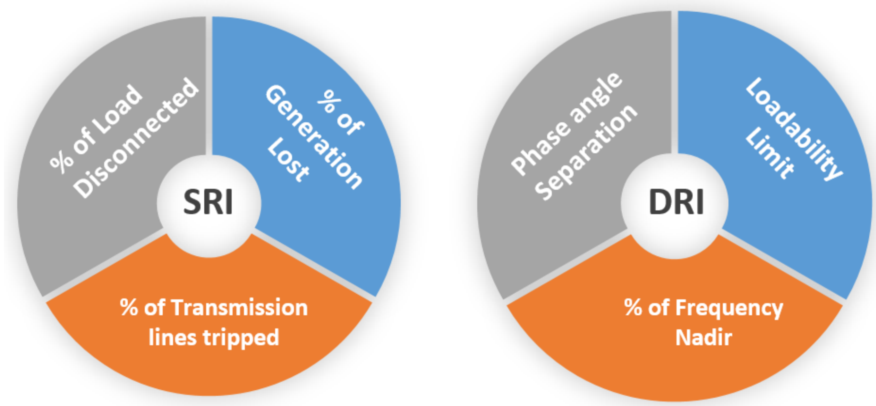


Figure 2-2. Severity Risk Index (SRI) and Dynamic Resilience Indicator (DRI).

2.3.4 Weighted Short Circuit Ratio (WSCR)

Short Circuit Ratio (SCR) is a metric that has traditionally represented the voltage stiffness of an electric grid. It is measured at a resource point of interconnection (POI) [7], and can identify weak areas of the grid within the network at a specified point. The SCR is calculated before the disturbance occurs and at the post-restorative phase. The SCR provides information about the reliability implications and the risk associated with high-level integration and penetration of Inverter Based Resources (IBR) into the BES. Several approaches have been proposed in the literature to calculate the SCR for a system with high penetration of renewable generation including ERCOT's weighted SCR (WSCR) method. The Weighted Short Circuit Ratio (WSCR) has been recently applied in Texas to assist in defining operational limits for total transmission of power from inverter-based resources across key power system interfaces [8].

The WSCR is defined as:

$$WSCR = \frac{\sum_i^N SCMVA_i \times P_i}{\sum_i^N P_i}$$

where $SCMVA_i$ is the short-circuit capacity at bus i without current contribution from non-synchronous generation and P_i is the MW output of the non-synchronous generation to be connected at bus i, and N is the number total number of non-synchronous generation resources.

2.3.5 Cumulative customer energy demand not served

This performance-based metric is the amount of service (electrical and natural gas) not met at a time, t, for a given event. It can be represented as:

$$P(t) = D(t) - S(t)$$

where $S(t)$ represents the energy supply and $D(t)$ represents the energy demand, both of which are a function of time. For electric power, $P(t)$ is the MWh not served and for natural gas, $P(t)$ is the MJ or MMBTU not served. $P(t) > 0$ represents a loss of service because energy demands exceed supply.

2.3.6 Critical customer energy demand not served

Critical customers are defined as loads that must be served to keep critical infrastructure in service (e.g., hospitals, police stations, generators that are required to power a substation). Just as provided above, this metric represents the amount of critical energy demand not served.

2.3.7 Time to Operational Recovery

This metric describes how long it takes for a system to fully recover from an event. It is the period after a widespread outage through initial restoration to a sustainable operating state. The time to is divided into two categories:

- Time of Operational recovery: The time it takes for customers to be fully reconnected.
- Time of Infrastructure recovery: The time it takes for the affected infrastructure to be fully restored.

2.3.8 Time to Infrastructure Recovery

This metric is primarily an economic term that is often difficult to precisely define and depends heavily on the extent of damages and time to recovery.

2.4 Reliability Metrics

This section considers the following reliability metrics:

1. Planning Reserve Margin.
2. Loss of Load Probability (LOLP).
3. Loss of Load Expectation (LOLE).
4. Effective load Carrying Capacity (ELCC).
5. Expected Unserved Energy (EUE).
6. System Average Interruption Frequency Index (SAIFI).
7. System Average Interruption Duration Index (SAIDI).
8. Customer Average Interruption Duration Index (CAIDI).
9. Customer Total Average Interruption Duration Index (CTAIDI).

10. Customer Average Interruption Frequency Index (CAIFI).
11. Number of Natural gas service interruptions.
12. Duration of Natural gas service interruptions.
13. Frequency of Natural gas service interruptions.

It should be noted that the metrics SAIFI, SAIDI, CAIDI, CTAIDI, and CAIFI (presented in subsections 2.4.6– 2.4.10, respectively) are primarily used as metrics for analysis of electric distribution systems. Since this project is focused on analysis at the transmission level, these metrics were aggregated at the nodal, zonal, and regional levels of the transmission models developed for this project.

2.4.1 Planning Reserve Margin

This is a primary metric used to measure resource adequacy. It is the percentage of additional capacity (anticipated or prospective) over demand. This metric helps to gauge the amount of generation capacity available to meet expected demand. The planning reserve margin is computed as:

$$Reserve\ Margin(\%) = \frac{Capacity - Load}{Load} \times 100$$

2.4.2 Loss of Load Probability (LOLP)

LOLP is the probability of system daily peak or hourly demand exceeding the available generating capacity during a given time period:

$$LOLP = (A - L < 0)$$

where A is the available capacity available to meet the system peak load L, and p denotes probability. LOLP is calculated by convolving the capacities and forced outage rates of the installed generation fleet. This produces a capacity-outage probability table that contains the probability of having outages of different MW levels. The other method is a Monte Carlo simulation that is employed to calculate the LOLP of a system. Then LOLP can be expressed mathematically as:

$$LOLP = \frac{\sum_{i=1}^{N} S_e}{N}$$

where Se is a simulation in which at least one event occurs when load and operating reserve obligations exceed resources or some event threshold limit.

2.4.3 Loss of Load Expectation (LOLE)

LOLE is the expected number of days per time period for which the available generation capacity is insufficient to serve the demand at least once per day.

LOLE is defined as the average number of days on which the daily peak load is expected to exceed the available generating capacity. Assuming a Monte-Carlo simulation is employed, LOLE in hours/year is defined mathematically as:

$$LOLP = \frac{\sum_{i=1}^{N} r_i}{N}$$

2.4.4 Effective Load Carrying Capacity (ELCC)

Effective Load Carrying Capacity (ELCC) is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved loads caused by forced outages, load uncertainty, and other factors. The ELCC provides a consistent way to assess the capacity value of resources.

2.4.5 Expected Unserved Energy (EUE)

The Expected Unserved Energy (EUE) is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours.

2.4.6 System Average Interruption Frequency Index (SAIFI)

SAIFI measures the number of times on average each customer experiences a power interruption:

$$SAIFI = \frac{Total\ number\ of\ custumers\ interruptions}{Total\ Number\ of\ Customers\ Served}$$

2.4.7 System Average Interruption Duration Index (SAIDI)

SAIDI measures the total number of minutes on average each customer is without electric service for a given period of time:

$$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ number\ of\ customer\ served}$$

2.4.8 Customer Average Interruption Duration Index (CAIDI)

CAIDI measures the average time required to restore service:

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ number\ of\ customer\ interruptions}$$

$$CAIDI = \frac{SAIDI}{SAIFI}$$

2.4.9 Customer Total Average Interruption Duration Index (CTAIDI)

CTAIDI measures the average time required to restore service. It is the total average time customers were without power for customers who actually experienced an interruption:

$$CTAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ number\ of\ customer\ interrupted}$$

2.4.10 Customer Average Interruption Frequency Index (CAIFI)

CAIFI measures the frequency of sustained interruption for customers experiencing sustained interruption:

$$CAIFI = \frac{Total\ number\ of\ customers\ interruptions}{Total\ Number\ of\ Customers\ interrupted}$$

2.4.11 Number of Natural Gas Service Interruption

This metric counts the total number of natural gas disruptions that affect customers. These disruptions include unplanned service interruptions and leaks.

2.4.12 Duration of Natural Gas Service Interruption

This metric defines duration of outage as a result of a natural gas service interruption. The duration of natural gas disruption varies widely on the basis of the type of events. Disruptions that require the excavation of a pipeline to find and repair a leak can take considerable time. The time of the year when the disruption occurs also has a high impact on the effect associated with the interruption. Interruptions of a few hours in the summer in a residential area may generally be of low consequence, however, during the winter, the same interruption scenario can cause a more significant economic damage.

2.4.13 Frequency of Natural Gas Service Interruptions

This metric measures the incident rate of natural gas service interruptions per customer per year.

2.5 Monte Carlo Implementation for Resource Adequacy Assessment

Resource Adequacy (RA) is defined as an ability (or condition) to supply the demand all the time. Probabilistic resource adequacy assessment is widely utilized to quantify the resource shortfall risk by driving the mapping between quantified uncertainties in system operating conditions (e.g., forced outages of generators and lines) and probability distributions for outcomes of interest. The resulting quantities are then leveraged to calculate standard reliability metrics, e.g., loss of load expectation (LOLE).

In general, there are two computational approaches: analytical methods and simulation methods. The simulation approach becomes more appropriate due to its flexibility to incorporate a wide range of different scenarios and its capability to provide statistical results for the future electric grid subject to increasing uncertainties. In this approach, the Monte Carlo Simulation (MCS) method is an essential tool for analyzing events that exhibit a probabilistic behavior. It provides estimations for the reliability indices within an interval of confidence by simulating the behavior of the power systems.

To implement the MCS, one needs to define and model the system. The simplest form is the single area generating system, which considers the power system as a region not based on buses. In this form, the key step is to model generation units and load within that region. For generators, the simplest approach is to use the two-state model (i.e., on and off) as shown in **Figure 2-3**. Note that this approach may only be valid for the base load units such as nuclear and large coal-fired plants. For loads, the hourly system load prediction for a year is used. One can also represent load prediction by a daily peak load variation curve.

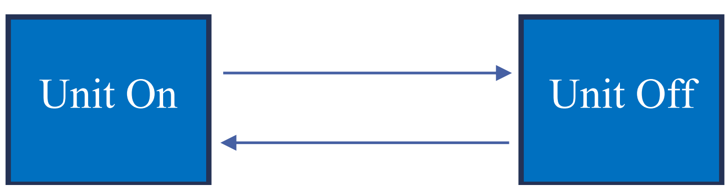


Figure 2-3. Two state model for the generation unit.

There are generally two methods for the MCS: Non-sequential MCS (NS-MCS) and Sequential MCS (S-MCS). The S-MCS method is the most detailed simulation approach and allows one to simulate the chronological evolution of the system with individual unit-level outage states. It is facilitated by utilizing the mean-time-to-failure (MTTF) and mean-time-to-repair (MTTR) of each generation unit, their maximum capacity, and the hourly peak load of the system as inputs.

Figure 2-4 and **Figure 2-5** present results to validate the feasibility of the S-MCS approach in calculating the standard reliability metrics. These results are based on the simple single area generating system consisting of five (5) generators along with the deterministic hourly load prediction for a year without random noise. Note that all generation units are modeled as a simple two-state model (i.e., on and off) as shown above in **Figure 2-3**. Using this setup, we obtained the results for a chronological system state transition process using the S-MCS method, which are shown in **Figure 2-4**.

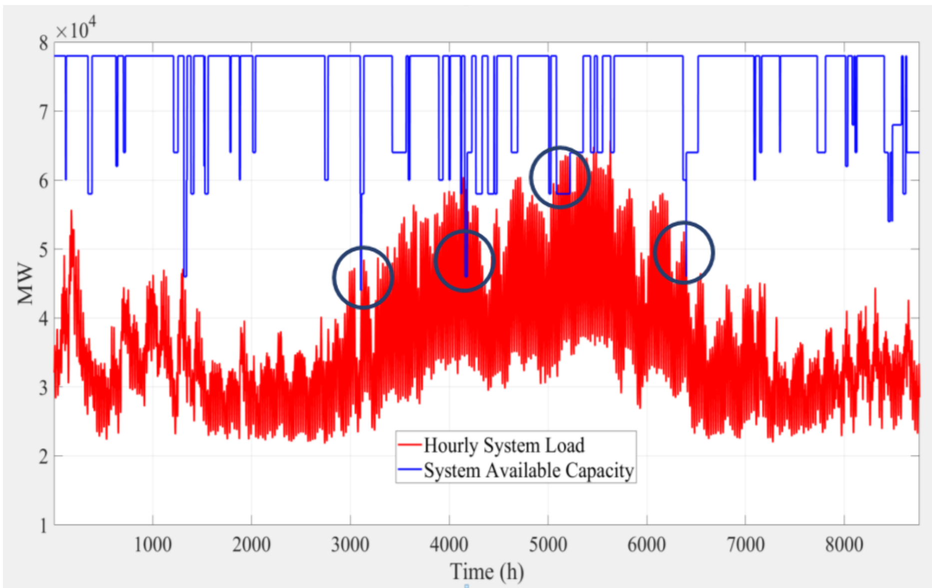


Figure 2-4. One sample of system available capacity model in a year.

Using these results, we then measure quantities such as how much and how long the system is unable to supply the predicted demand. This is then used to calculate, for example, loss of load duration (LOLD) as shown in

Figure 2-5.

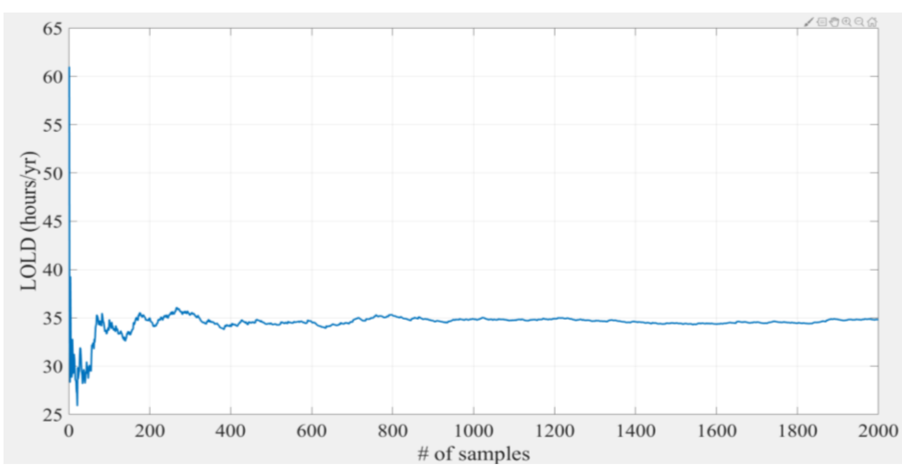


Figure 2-5. Average value of loss of load duration. The x-axis is the number of S-MCS simulations. The y-axis is the average value, which converges to about 34 hours/year for this specific example.

2.6 Interactions between the resilience task and the other NTRR tasks

This section illustrates how the metrics are evaluated based on input from the other NTRR project tasks. This is meant to serve as a walkthrough that explains the process by which the simulations of the base cases subject to the various scenarios were turned into values for the reliability/resilience metrics.

Figure 2-6 depicts a flowchart with the key steps involved in the process of calculating and visualizing the reliability and resilience metrics for the scenarios simulated for each interconnection. The flowchart shows an iterative approach once the metrics are calculated and visualized. Most of the iterations were based on varying the extent of the scenarios to determine the sensitivity of the metrics to the time duration and damages incurred to the grids (both gas and electric) from the scenarios. Depending on the resolution needed for the analysis (node level, interconnection level, service area, etc.), the iteration(s) may require re-starting from the initial node identification step. This is not always necessary.

Figure 2-7 and **Figure 2-8** illustrate a deeper dive into the scenario simulations by region (EI in **Figure 2-7** and WI in **Figure 2-8**). This deeper dive corresponds to a breakout of the first 3 boxes in the upper left of **Figure 2-6** for the specific scenarios to be run for the EI (**Figure 2-7**) and the WI (**Figure 2-8**). Note that **Figure 2-7** and **Figure 2-8** correspond to Tasks 4 and 5 of the NTRR Statement of Work (SOW). The remaining three boxes in **Figure 2-6** correspond to the bulk of the effort for Task 2 (R&R metrics task). Task 3 of the NTRR project is the creation of the base cases (combined natural gas and electric) for the EI and WI, respectively. Task 3 is necessary to create the baseline from which the scenarios in Tasks 4 and 5 can be drawn from. Therefore, Task 3 is a necessary prerequisite for Tasks 2, 4, and 5. It should be noted that project personnel from the R&R metrics task fully participated in Task 3 efforts (both WI and EI). Finally, **Figure 1-1** illustrates the dependencies between the different tasks more explicitly. It can be seen that Task 2 underpins the results of Tasks 3-5 since the resilience analysis is needed to be conducted to tie together the entire national base case (electric interconnections with the natural gas infrastructure) for each of the extreme weather scenarios.

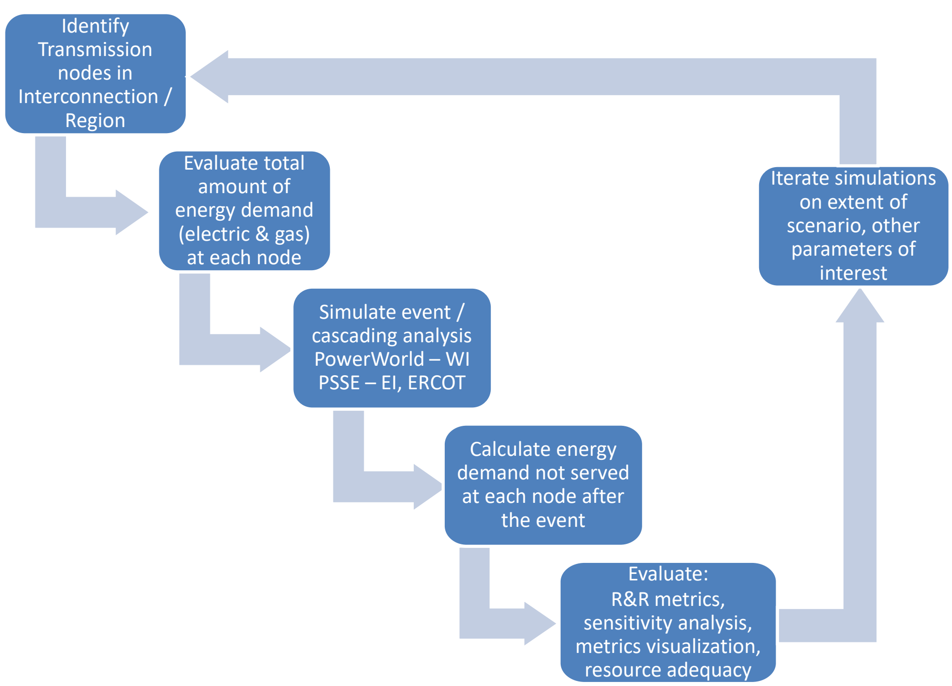


Figure 2-6. Flowchart of resilience analysis process.

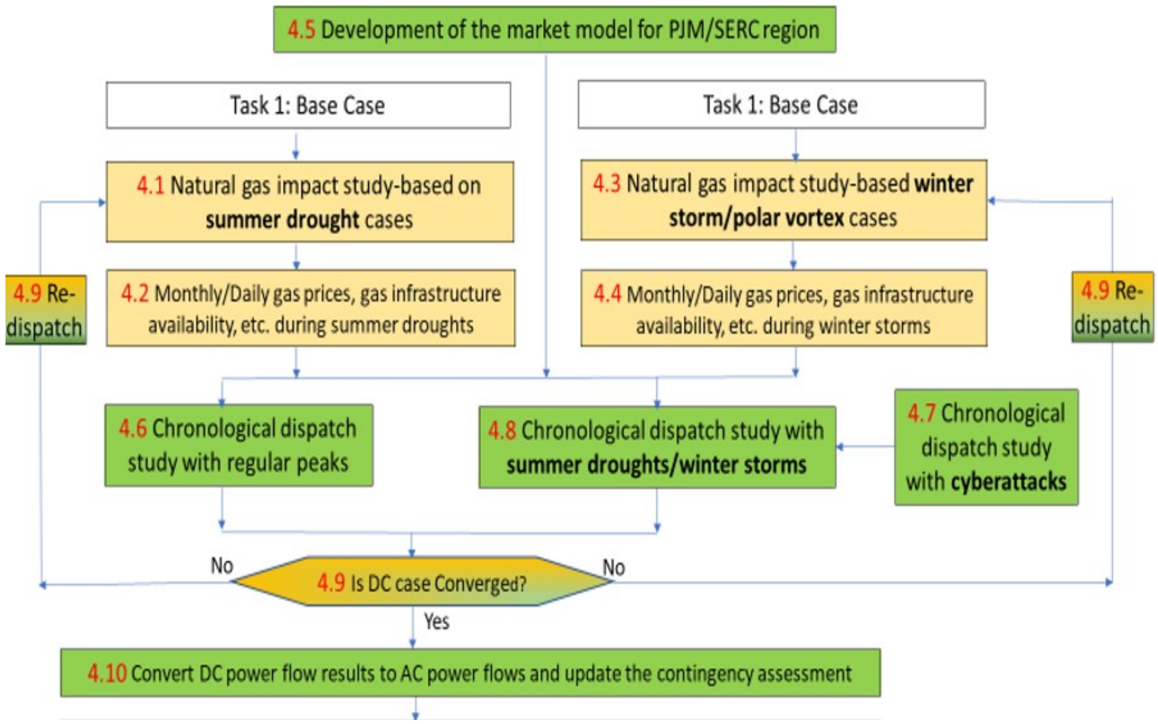


Figure 2-7. Flowchart of scenario simulation process for the Eastern Interconnection.

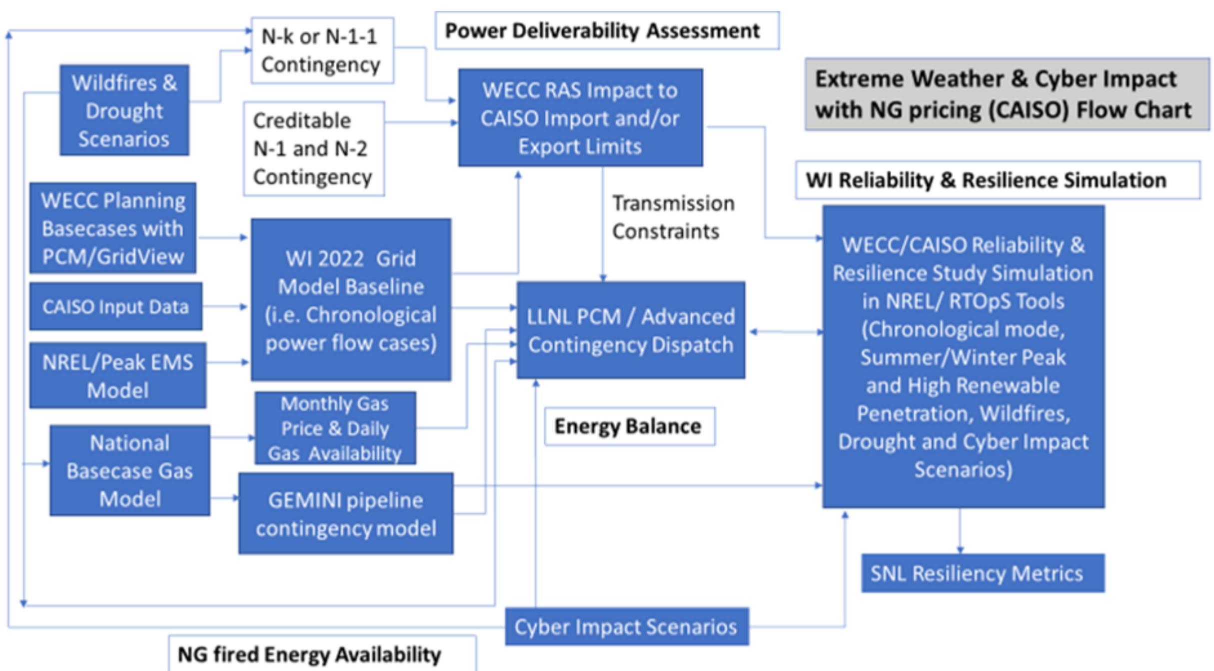


Figure 2-8. Flowchart of scenario simulation process for the Western Interconnection.

2.7 Software Tools

PSSE and PowerWorld are the primary software tools deployed for the resilience analysis work of Task 2. There are other tools that were deployed in NTRR work (e.g., production cost modeling tools and gas infrastructure modeling tools) that primarily serve as inputs to PSSE and PowerWorld. The Task 2 project team was not as deeply involved in running these software tools. Instead, these software tools are discussed in the final reports for Tasks 3 – 5. There was also a need to develop short scripts that calculated the metrics using the equations presented earlier in this report as well as data parsing functions. These scripts and functions were developed in Matlab and Python, respectively.

PSSE (product of Siemens) is a power system dynamics software tool that simulates the impact of transient events on large power systems (up to 100K buses) to observe dynamic behavior in the 0.1 – 3.0 Hz range. This corresponds to both small signal stability and transient stability phenomena that have been identified as culprits in some of the largest blackouts in North America history. Because of its prevalence in transmission planning departments of eastern North America utilities, there are significant datasets and models available in PSSE that are widely used in simulations of the EI. Therefore, PSSE was chosen as the primary electric grid simulation tool for studying scenarios in the EI.

Likewise, PowerWorld has become widely used in the western North America utility community. Models and datasets compatible with PowerWorld and available through WECC (Western Electricity Coordinating Council) make it a natural choice to study scenarios in the WI. Background software investigation by the Task 2 project team determined excellent compatibility features between the output files of PSSE and PowerWorld. This enabled R&R metrics analysis methods developed within the project to seamlessly work on output files from both EI and WI simulations.

2.8 Conclusions

To quantify power supply reliability and resiliency during extreme weather conditions, the Task 2 project team has developed a new set of indices with input from the TRC and DOE. With these new metrics, it is possible to measure the overall grid reliability and resiliency during different phases of extreme events, namely, event onset, during interruption, and recovery. We tested these indices on several credible future extreme weather events to provide a scientific approach to measure their impact on customers and infrastructure. This analysis tool provided a sound technical basis for making recommendations to improve reliability and resiliency, to mitigate the impact of future extreme weather events, and to help make investment recommendations needed to ensure successful renewable integration.

3. Task 3: National Base Case

3.1 Introduction

An iterative process is being used in the development of the base models including interim reporting on the base model development. In case of conflicts between EIA/NERC data and aggressive state policies, a balance was be achieved with DOE and industry input. Assumptions were be validated with key industry entities, both TRC members and others, on a best-efforts basis. Both wind and solar locations were based on known projections as well as load and cost analysis together with industry inputs. These locations are directly connected to historical weather years and generation profiles for use in production cost modeling.

The base case scenarios allow for analysis and understanding near future reliability and resiliency risks that arise from an unmanaged or poorly managed transition. Part of the base model development includes identification of issues that arise between the various region and state RPS goals. Evaluation of the metrics established in initial project deliverables highlighted system vulnerabilities and could be used to select more impactful sensitivities to evaluate in later tasks.

Figure 3-1 shows the interdependencies of the electric and natural gas cases into a combined national base case.

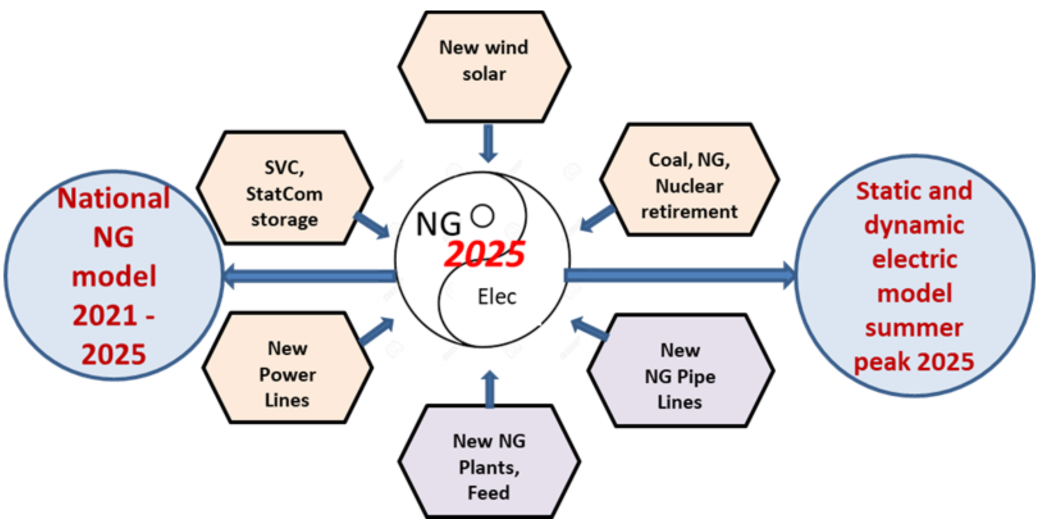


Figure 3-1. Interdependency of the Gas and Electric Cases into a Combined National Base Case

3.2 National Base Case East

3.2.1 Task Outline

This section provides a summary of the achievements for Task 3 of the NTRR project. The main focus is the base case development of the 2025 EI power grid. The major tasks completed by the team can be summarized as follows.

Task 3.1 – Development of the 2025 EI Summer Base Case

- Collected and compared information of generation additions and planned retirements from public data sources.

- Developed power flow model of 2025 EI Summer Base Case, reflecting Tier 1 capacity additions planned in the interconnection queues and confirmed retirements.
- Implemented transmission expansion and upgrades in the extended PJM area.
- Developed dynamic models of the 2025 EI Summer Base Case.

Task 3.2 – Grid Strength Analysis

- Evaluated the impact of renewable generation on short circuit MVA level of the PJM area.
- Conducted voltage impact studies in Dominion Energy Virginia (DEV) area, using 70% composite load models.
- Identified potential weak grid issues and critical conventional generation plants for supporting grid strength.

3.2.2 Data collection for target scenario creation for the 2025 EI Summer Base Case

To develop a projected 2025 EI Summer Base Case based on 2024 MMWG summer peak model, generation additions and planned retirements by 2025 needs to be addressed and transmission expansion and upgrades need to be integrated. The team starts the development by collecting information from different public data sources. Projections from different data sources are compared and key findings and decisions are reported in this section.

3.2.2.1 Findings, Decisions and Conclusion

Through the abovementioned tasks, the team could provide the following findings, and conclusions:

Data collection for generation additions and planned retirements

1. NERC LTRA 2020 [10] provides conservative projections of future generating capacity, considering mainly Tier 1 additions[3] and confirmed retirements.
2. EIA Annual Energy Outlook (AEO) 2021 provides more aggressive projections for future capacity additions and retirements, especially for renewable resources. EIA AEO uses a market-based approach to determine the optimal strategy for meeting expected demands and complying with environmental regulations that minimize the total investment and operating costs during the planning horizon. Form EIA-860 [11] reports on existing generation, planned capacity additions and confirmed retirements.
3. Generation interconnection queue provides lists of the interconnection requests submitted to Independent System Operators (ISOs). Project status projected in-service dates, and POI information are available in the queues; these are useful data for projecting and implementing future capacity additions.
4. Since EIA data does not provide detailed projections outside of the U.S., the projections of Canada Energy Regulator (CER) were collected for the Canadian areas in EI and compared to NERC's projections for the same areas. It was found that both were similar except in few explainable or inconsequential cases, which validated NERC's projections for these areas. Therefore, it was determined that NERC's projection is applicable for the target scenario creation of the Canadian areas.

[3] Tier 1 projects include generation interconnection projects that are already under construction or have signed/approved Interconnection service agreement.

5. Projections from all six ISOs in the EI region were collected but comparison with EIA, and NERC projections led to some complications. First, ISOs forecast generation capacity mix for different years based on local targets or regulations, which makes harmonization of the projections for a common year difficult. For example, New York Independent System Operator (NYISO) and MISO provides forecasted generation mix for 2030 and 2033 respectively with no trend data. Using interpolation to estimate 2025 projection for both ISOs could lead to highly inaccurate results since generation buildouts are typically not uniform across years. Furthermore, ISOs often rely on scenario analysis with disparate underlying assumptions which makes combination of their projections even more challenging. Some EI regions also do not have ISOs, which effectively leaves them out of this validation process. For these reasons, the use of ISO projections to validate EIA and NERC data was put on hold.
6. Data collection from utilities' Integrated Resource Plans (IRPs) was also halted due to the large number of electric utilities in the EI region *(about 3,461)* coupled with the fact that some states do not require their utilities to file IRPs. It was also found that some states allow certain parts of the IRPs to be redacted from public view which further limits the usefulness of this approach.
7. The team made the final decision to develop the 2025 EI Summer Base Case, which includes only Tier 1 capacity additions and confirmed retirements by Year 2025. The team developed the 2025 scenario based on 2019 Series 2024 MMWG summer peak model.

Data collection and implementation of the Transmission expansion plan in EI

1. Due to the large number of proposed transmission upgrades in the EI region, the team decided to narrow the focus on baseline reliability projects since these have the highest probability of being implemented to ensure compliance with NERC standards and other regional reliability standards. Furthermore, only new BES-level transmission line projects were selected for all regions except the PJM area, to only account for major topology changes in the network.
2. Using the above criteria, 43 transmission upgrades were selected for the PJM area, and 53 new transmission line projects were selected for other areas.
3. In the PJM area, 4 of the selected transmission upgrades were already found in the 2024 MMWG model, 20 were successfully implemented, and 3 were not implemented due to lack of sufficient information.
4. To save time, it was decided to halt the transmission upgrades for the other areas for now. These projects may still be implemented if time permits or to relieve any observed transmission congestion that may arise when the cases are built.

3.2.2.2 Wins

1. Investigated major data sources for future projections of generating capacity and corresponding assumptions.
2. Compared future projections from different sources by area and resource type.
3. Determined the target scenarios for 2025 Model, base case by including Tier 1 capacity additions and confirmed retirements.
4. Collected baseline reliability transmission upgrades for all EI regions from 14 different sources including NERC report, ISO transmission expansion reports, Reliability Coordinator reports, and reports from major utilities.
5. Successfully implemented baseline reliability transmission expansion and upgrades in the PJM area.

3.2.2.3 Data sources for Generating Capacity Projections

To build the 2025 Eastern Interconnection model, the first step was to determine the projections of different generation resources of Year 2025 by regions. There are several data sources for projections of different generating resources. In this task, data are mainly collected from the following three sources,

- EIA Annual Energy Outlook (AEO) 2021
- NERC Long term reliability assessment (LTRA) 2020
- Generation Interconnection Queue from different ISOs

All these data sources have made assumptions when projecting future generation capacities, which will be introduced in this section.

3.2.2.3.1 EIA AEO 2021

EIA AEO projections are based on National Energy Modeling System (NEMS) by using a market-based approach, subject to regulations and standards. For each fuel type, NEMS balances energy supply and demand considering competition across various fuels and sources. The projections period currently extends to 2050. NEMS is a modular system, as shown in **Figure 3-2** [12], which represents the fuel supply, conversion, and demand of the energy system. NEMS calls each component module in sequence until the delivered fuel prices and the demands have converged. An integrating module is included to control the execution of each of the component modules by performing as a central database to store and pass inputs and outputs between the component modules. **Figure 3-3** shows the information flow in the NEMS.

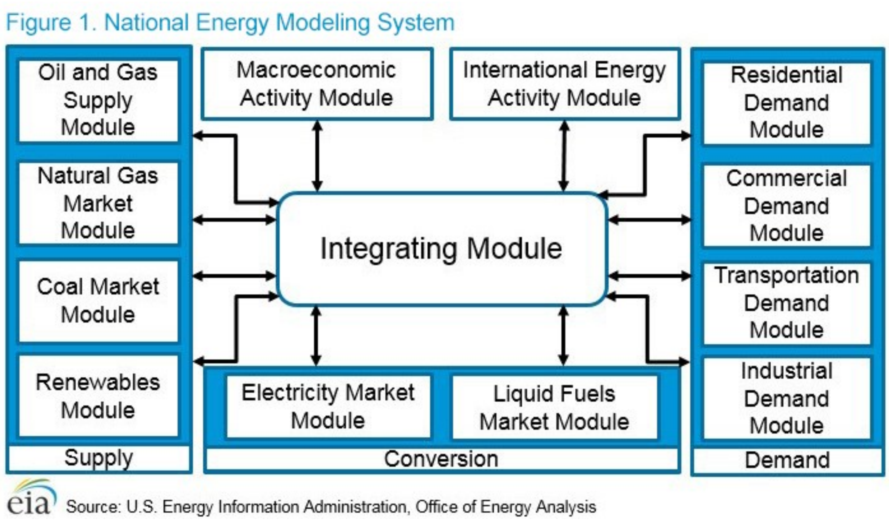


Figure 3-2. National Energy Modeling System

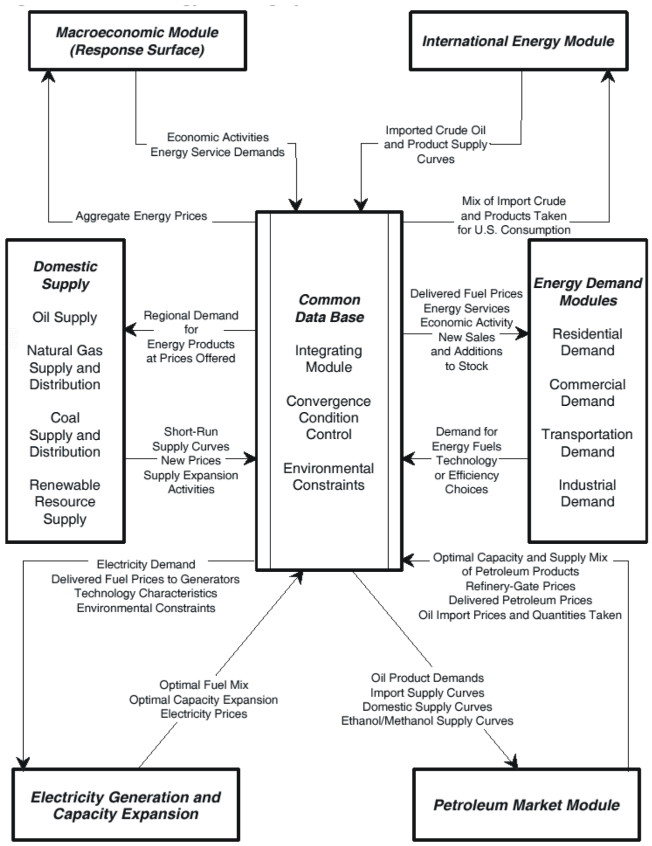


Figure 3-3. Information flows in the NEMS

The Electricity Market Module (EMM) provides projections of future capacity additions of carious fuel resources. In each model year, EMM receives the electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system model and macroeconomic parameters from the NEMS macroeconomic module. EMM estimates the actions taken by electricity producers to meet demand in the most economical manner. EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the Integrating Module. The model iterates until a solution is reached for each forecast year.

There are 25 electricity supply regions considered in the EMM, as shown in **Figure 3-4**. The regions are based on NERC regions and subregions. Apart from Texas Reliability Entity (TRE), the other NERC regions are further split into subregions.

The EMM consists of several submodules, including Electricity Load and Demand (ELD), Electricity Capacity Planning (ECP), Electricity Fuel Dispatching (EFD), and Electricity Finance and Pricing (EFP) [13]. Electricity demand is represented by load curves, which vary by region, season, and time of day. Capacity expansion is determined by the least-cost of the additions, including capital cost, operating and maintenance cost and fuel cost. Operating (dispatch) decisions are made by choosing the optimal mix of plants that minimizes fuel, operating and maintenance, and environmental costs, subject to load demands and environmental constraints.

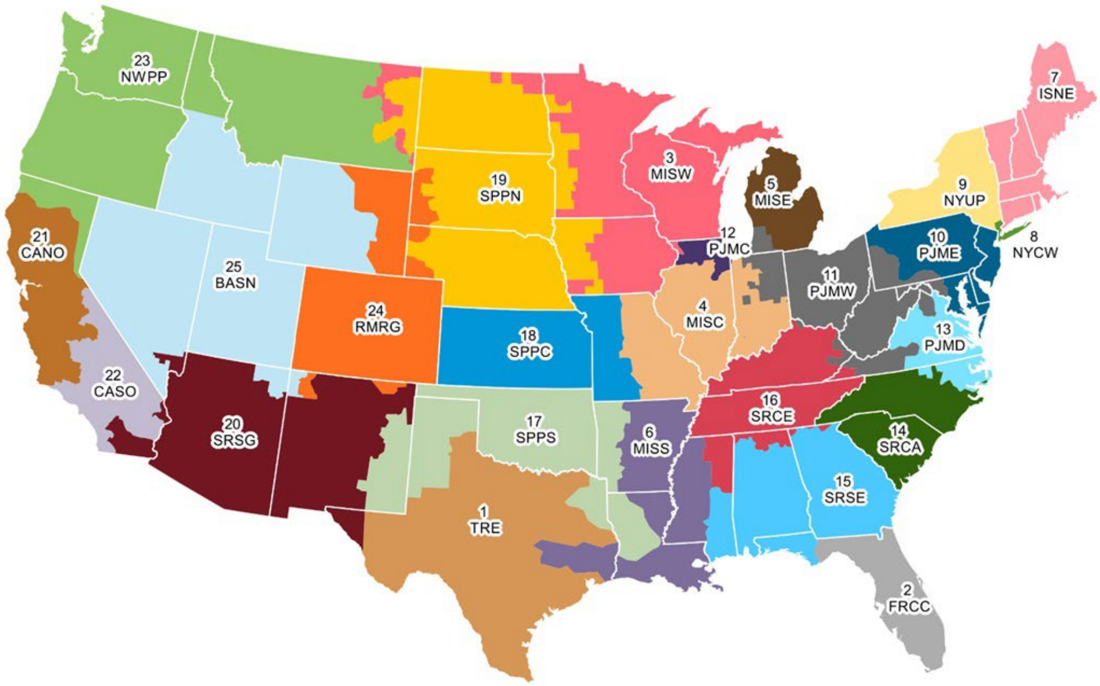


Figure 3-4. Electricity supply regions

The solution sequence of the submodules could be summarized as follows [13],

1. ELD constructs load curves for each region and season.
2. ECP projects the construction of new generating plants, the retirements of existing plants and the level of form trades.
3. EFD dispatches the available generating units, allowing surplus capacity in selected regions to be dispatched for another region's needs through trading.
4. EFP calculates electricity prices, based on both average and marginal costs.

The detailed modeling of each submodule is complicated and could be referenced in [13]. In this section, only major assumptions of the ECP submodule will be introduced.

The ECP submodules provides projections of future capacity additions, which could be used as a reference for the development of the 2025 Eastern Interconnection model proposed in this task. The objective of this submodule is to determine the change of the mix of the generating capacity subject to future demands and environmental regulations. It considers investment decision for new capacity and evaluates retirement decisions for existing plants. ECP uses a linear programming formulation to determine the optimal strategy for meeting expected demands and complying with environmental restrictions that minimize the total investment and operating costs during the planning horizon. The state regulations and legislation modeled in AEO 2021 are listed in [14].

The fundamental assumptions of the projections of future generating capacity of EIA AEO 2021 are listed as follows,

- Capacity additions that are already under construction and scheduled retirements are assumed to be completed as reported in the Form EIA-860, *Annual Electric Generator Report* [15].

- ECP only determines capacity additions and retirements over and above those currently planned that are required to meet new demand, replace retiring capacity, and comply with environmental regulations.
- Bulk power purchases between electricity supply regions are represented with the limits on power flows based on region-to-region transmission constraints, derived from Form EIA-411, *Coordinated Bulk Power Supply Program Report* [16]. Interregional transmission capacity can be added, and new plants can be built in one region to serve another region. International trades with Canada as well as firm transactions with Mexico are also incorporated.
- Projected capacity values are net summer capacity, which is the steady hourly output that generating equipment is expected to supply to system load during summer peak demand.

3.2.2.3.2 NERC LTRA 2020

The NERC LTRA is developed annually by NERC to study the resource adequacy of the BPS in North America. The assessment was developed based on data and narrative information collected by NERC from the six Regional Entities (REs) on an assessment area basis to independently assess the long-term reliability of the North America BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period.

Projections in this assessment are not predictions of what will happen, rather they are based on information supplied in July 2020 about known system changes. The LTRA is based on several assumptions,

- Supply and demand forecasts are based on industry forecasts submitted and validated by July 2020. Any subsequent plan changes may not be fully represented.
- Peak demand forecasts are based on average weather conditions and assumed forecast economic activity at the time of submittal.
- Future generation and transmission equipment ware commissioned, and in-service as planned, planned outages take place as scheduled, and retirements take place as proposed.

LTRA 2020 provides regional assessment, including projections of total internal demand, capacity additions by Tier, and fuel composition in terms of on-peak capacity. Capacity additions are reported in the following categories [10],

- Tier 1 Capacity.
    - Construction complete, but not in commercial operation.
    - Under construction.
    - Signed/approved Interconnection service agreement.
- Tier 2 Capacity.
    - Signed/approved completion of a feasibility/system impact/facilities study.
    - Requested Interconnection service agreement.
- Tier 3 Capacity.
    - Other capacity that does meet the above requirements.

Fuel mix changes are evaluated by considering only Tier 1 capacity additions. An assessment area-based table of derating factor are also provided for solar and wind resources, representing the ratio between on-peak demand capacity and nameplate capacity.

3.2.2.3.3 Generator Interconnection Queue

ISOs, including PJM, Midwest Independent System Operator (MISO), The Independent System Operator – New England (ISO-NE), New York Independent System Operator (NYISO) and Southwest Power Pool (SPP), provides the generator interconnection queues, which contain lists of submitted generator interconnection requests. Though there may be differences of terminology between ISOs, the in-queue projects are identified by project status, on-peak capacity, fuel type, projected in-service date and POI information. Project status could normally be generalized into the following,

- In service.
- Under construction.
- Signed/Approved Interconnection service agreement.
- Study phase (system impact study, feasibility study, facilities study, etc.).
- Suspended/Withdrawn.

For SERC regions, including SERC-E, SERC-C, SERC-SE, and SERC-FPs, since there is not an ISO to provide the queue lists, generation interconnection information is collected from major utilities regionally.

3.2.2.3.4 Other sources considered - Utilities Integrated Resource plans (IRPs)

Integrated resource plan (IRPs) are roadmaps published annually or biannually by large electric utility companies to document their expected generation acquisitions and retirements to meet peak and energy demand over a long-time horizon, usually between 15 to 30 years. IRPs detail and justify likely future investments decisions of these utilities, thereby serving as ideal reference documents for states, shareholders, and other interested stakeholders. In the creation of IRPs, utilities often consider myriads factors in the analysis that produces the IRPs, these factors include load forecasts, weather forecasts, expected economic growth, current and expected future regulations, public opinions, and network reliability issues, among others. Many of these factors are probabilistic since there is no way to guarantee their future status, thus, many IRPs include multiple alternative resource plans to account for different future scenarios. For example, Dominion Energy – Virginia 2020 IRP includes four alternative resource plans apart from its reference plan with different level of Carbon Dioxide (CO_2) emission restrictions requiring different penetration levels of clean energy and energy storage resources [17].

Bearing in mind the wealth of data that is contained in a typical IRP, the aggregation of data from the IRPs of all utilities in the EI area was considered as an approach to validate the generation projections from NERC and EIA for the creation of the 2025 EI models. However, this approach had the following limitations:

1. Many states' public utilities commissions (PUCs) in the EI area do not require their utilities to file IRPs as shown in **Figure 3-5** [18]. Therefore, future generation projections for these states may not be available from their individual utilities. Even for states that do require IRPs, there are considerable variations in their degree of rigor, stakeholder feedback process, and degree of regulatory scrutiny [19].

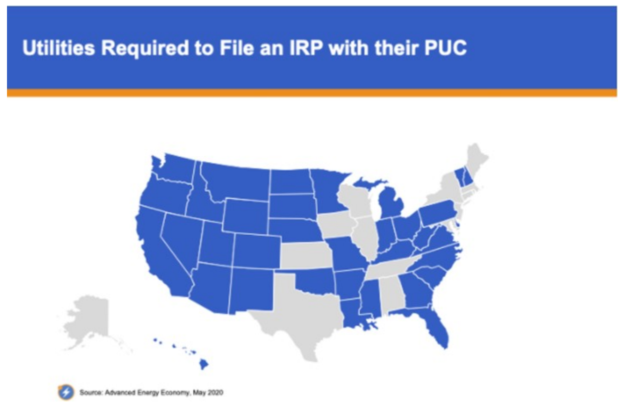


Figure 3-5. Utilities required to file an IRP with their PUC

2. Expectedly, only existing, and mostly large utilities file publicly available IRPs, therefore, aggregation of IRPs' projections ignore potential generation additions from new market entrants and smaller power generating entities. This may lead to an underwhelming estimation of future generation capacity.
3. Deregulated markets often have hundreds of electricity generation companies, in fact, 3,461 were found in Form EIA-860 generator data for the EI area [15]. Hence, data collection from these large number of utilities makes this approach infeasible within the project timeline.
4. Since state PUC requirements vary, parts of the publicly available IRPs of some utilities are redacted (an example is presented below in **Figure 3-6**), hence, some important information or considerations for the project may be inaccessible if IRPs are used.

After reviewing the results of the various portfolio analyses, Cleco Power identified a preferred portfolio. The preferred portfolio includes acquiring up to 400 MW of installed solar capacity, as well as up to 1,000 MW of installed wind capacity. [redacted]

As discussed in Section 8, the preferred portfolio is based on resource selections by the Aurora model given load, commodity, and market assumptions at this time. Actual results from a competitive RFP may significantly vary. Therefore, the preferred portfolio is used as a guide toward developing an Action Plan and is not, itself, considered a definitive action plan.

[redacted] While the IRP analysis includes unit retirements and new

Figure 3-6. Redacted 2019 IRP of East Kentucky Power Cooperative [21]

3.2.2.3.5 Other sources considered - Projections from ISO reports

Data collection from ISOs was also considered because these entities annually publish resource adequacy reports which includes load forecasts and expected resource mix for the next 10 to 20 years. The load forecasts are calculated based on historical trends, weather forecasts, expected economic and population growth, regulations and government programs, penetration of new technologies, etc. On the other hand, generation capacity projections are based on deliverable generation addition and retirements projects on the ISO's interconnection queue. The deliverability of these projects is often judged based on the projects' progression stage e.g., design, study, approval, or construction stage. It is noteworthy that many of the potential additions in the interconnection queue may never be implemented and some retirement notices may later be withdrawn. For example, only 23% of projects that have started initiated an interconnection process have reached commercial operation in both PJM and ISO-NE as of December 2020 and April 2019 respectively [21], [22].

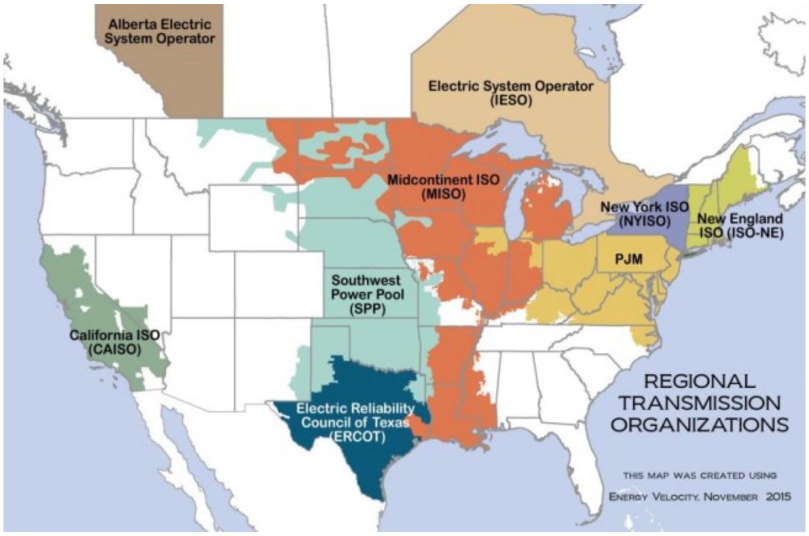


Figure 3-7. Regional Transmission Organizations/Independent System Operators in the U.S [23].

The major bottleneck related to the use of data from ISOs is that not all EI areas have an ISO as can be seen from the **Figure 3-7**. This limits the usefulness of these sources for the purpose of this project compared to the continent-wide NERC and nationwide EIA reports. Furthermore, the reporting style and format of individual ISOs can be quite different, thereby increasing the difficulty of integrating the data for comparison and implementation. Unlike load forecast, some ISOs (e.g., NYISO [24] and PJM [21]) do not report any extensive generation forecast studies outside of the committed or deliverable capacities in their interconnection queues. This is because their major goal is to ensure that known firm capacities can meet future load. Therefore, their studies tend to be more conservation with regards to generation additions with more emphasis on potential load growth and possible generation deactivations. In cases where generation forecast is carried out, they often vary in terms of target time period based on specific regional regulations and goals. Thus, collection of generation projections from different ISOs can be difficult to harmonize for a common year. For instance, NYISO's 2020 Reliability Needs Assessment (RNA) reports the regions generation mix for 2030 while MISO's 2020 Transmission Expansion Plan (MTEP) reports the generation mix for 2033 [24], [25]. Since annual generation buildouts are typically not uniform, estimation of both region's 2025 generation mix using common interpolation methods may result into highly inaccurate values.

Lastly, it is not unusual for ISOs to rely on scenario analysis to provide alternative forecasts for uncertain variables such as cost of fossil fuel and renewable energy technologies, new environmental regulations, continual governmental support, and even near-term impact of the Covid-19 pandemic, among others. These scenarios often rely on combinations of different viable assumptions that are hardly uniform across ISOs, therefore, the choice of scenario to incorporate into the overall model may not be obvious especially when no reference/base case is provided.

3.2.2.4 Transmission Expansion

The selected transmission upgrades were collected from several sources. Firstly, the NERC LTRA report and the individual ISO transmission expansion report were consulted. For areas without an ISO, reports from their reliability coordinators were used. Reports from major electric utilities was relied upon for areas that the reliability coordinator reports could not found. In total, 14 unique sources were consulted as shown in the table below.

Table 3-1. Sources consulted for 2025 EI Transmission expansion plan

NERC Region (State)	Sources
MISO	MISO Transmission Expansion Plan (MTEP) 2020 [25]
MRO (MB)	NERC Long-Term Reliability Plan (LTRA) 2020 [10], Manitoba-Hydro [26]
MRO (SK)	SaskPower [27]
NPCC (NE)	ISO-NE Regional System Plan (RSP) 2020 [22], ISO-NE Project List [28], NERC Long-Term Reliability Plan 2020 [10]
NPCC (NY)	NYISO Reliability Needs Assessment (RNA) 2020 [24]
NPCC (ON)	IESO Annual Planning Outlook (APO) 2020 [29]
NPCC (QB)	NERC Long-Term Reliability Plan 2020 [10], Hydro-Quebec [30]
SERC (AL, GA, KY, MS, TN)	Tennessee Valley Authority (TVA) [31]
SERC (FL)	FRCC Load & Resource Reliability Assessment 2020 [32]
SERC (NC)	NCTCP 2020-2030 Collaborative Transmission Plan [33]
SERC (SC)	Dominion Energy-SC Integrated Resource Plan 2020 [34]
SPP	SPP Integrated Transmission Plan (ITP) 2020 [35]

3.2.2.5 U.S. Projections

In this section, projections of EI needed for the development of the 2025 EI base case are compared, including peak demand, generating capacity and transmission expansion. Related data are collected by the end of 2020 and later updates may not be included.

3.2.2.5.1 Load Demand

Table 3-2. Load demand projections

Regions	NERC LTRA[1](MW)	2024 MMWG Summer Peak[2](MW)
FRCC	51,107	51,293
MISO	127,029	142,520
Manitoba Hydro	4,780	3,293
SaskPower	3,682	3,810
NPCC[3]	126,476	103,819
PJM	153,315	156,228
SERC	136,964	138,990
SPP	55,082	59,891
Total	658,435	659,844

Note:

1- Data from NERC LTRA 2020 Report. Numbers are projected total internal peak load demand of Year 2025, not including demand response.
2- Data from 2024 MMWG Summer Peak Model. Area grouping follows MMWG Procedural Manual [36].
3- NPCC region contains NPCC-Maritimes, NPCC-New England, NPCC-New York, NPCC-Ontario, and NPCC-Quebec.

3.2.2.5.2 Coal-fired generation

Table 3-3. Coal-fired generation projection

Regions	EIA Projected Increase (GW)		NERC LTRA Projected Increase (GW)[1]	
	PA	R	A	N
FRCC	0	0.342	-0.251	-0.267
MISO	0	18.062	-6.255	-6.654
NPCC	0	1.054	0	0
PJM	0	17.202	-2.292	-2.438
SERC	0	20.800	-0.76	-0.809
SPP	0	6.323	0	0

Notes: PA- Planned addition, R-Retirement, A-Available capacity during the hour of peak demand, N-Nameplate capacity

1- The ratio of available capacity to nameplate capacity is assumed to be 0.94.

3.2.2.5.3 Natural gas-fired generation

Table 3-4. Natural gas-fired generation projection

Regions	EIA Projected Increase (GW)			NERC LTRA Projected Increase (GW)[1]		Generation Interconnection Queue (GW)			
	PA	UPA	R	A	N	UC	Tier1	Tier 2	Tier 3
FRCC	2.26	0	3.421	0.223	0.237	*	1.112	2.463	0
MISO	2.186	5.787	3.641	-1.118	-1.189	4.646	4.646	4.859	0
NPCC	0.02	1.072	4.128	-1.509	-1.605	0	0	3.649	0
PJM	8.452	6.800	1.580	10.32	10.979	6.723	12.406	10.878	0
SERC	0	3.154	0.984	-0.897	-0.954	*	0.753	25.525	0
SPP	0	0	2.013	0	0	*	0.034	3.609	0

Note: PA- Planned addition, UPA-Unplanned addition, R-Retirement, A-Available capacity during the hour of peak demand, N-Nameplate capacity, UC-Under construction
1- The ratio of available capacity to nameplate capacity is assumed to be 0.94.
*- Information of under construction projects is not included in the interconnection queue

3.2.2.5.4 Nuclear generation

Table 3-5. Nuclear Generation Projection

Regions	EIA Projected Increase (GW)		NERC LTRA Projected Increase[1] (GW)	
	PA	R	A	N
FRCC	0	0	0	0
MISO	0	0.772	-0.810	-0.862
NPCC	0	0	0	0
PJM	0	0	-0.038	-0.040
SERC	2.200	0	2.204	2.345
SPP	0	0	0.035	0.037

Note: PA- Planned addition, R-Retirement, A-Available capacity during the hour of peak demand, N-Nameplate capacity

1. The ratio of available capacity to nameplate capacity is assumed to be 0.94.

3.2.2.5.5 Renewable generation

Table 3-6. Renewable Generation Projection

Regions	EIA Projected Increase (GW)		NERC LTRA Projected Increase (GW) [1]				Generation Interconnection Queue (GW)							
	Wind	Solar	Wind		Solar		Wind				Solar			
			A	N	A	N	UC	T1	T2	T3	UC	T1	T2	T3
FRCC	0	4.139	0	0	2.265	4.892	0	0	0	0	*	4.420	8.540	0.450
MISO	16.18	14.703	0.470	2.541	0.970	1.672	7.208	7.390	21.220	0	9.653	10.430	65.700	0
NPCC[3]	6.516	1.559	0.121	0.733	0.101	1.147	0.164	0.603	28.680	7.630	0.030	0.130	9.850	1.060
PJM	11.572	10.527	0.490	3.224	3.143	6.521	0.110	0.300	5.890	0	1.197	3.860	53.210	0
SERC	0.926	5.929	0.004	0.004	2.502	3.350	*	0.490	1.440	0	*	6.670	37.970	0
SPP	8.146	5.087	0.288	1.220	0.029	0.040	*	11.15	39.560	0	*	0.470	36.000	0

Note: PA- Planned addition, UPA-Unplanned addition, R-Retirement, A-Available capacity during the hour of peak demand, N-Nameplate capacity, UC-Under construction, T1-Tier 1 Capacity, T2-Tier 2 Capacity, T3-Tier 3 Capacity.

1- The ratio of available capacity to nameplate capacity is from Page 30 in [10].

*- Information of under construction projects is not included in the interconnection queue

3.2.2.5.6 Conventional Hydro and Pumped Storage generation

Table 3-7. Conventional Hydro Projection

Regions	EIA Projected Increase (GW)	NERC LTRA Projected Increase (GW)[1]		Generation Interconnection Queue (GW)			
		A	N	UC	Tier1	Tier 2	Tier 3
MISO	0	-0.028	-0.03	0.119	0.119	0.342	0
NPCC	0.005	0.005	0.005	0	0	0.057	0
PJM	0.003	0.023	0.024	0.023	0.023	0.537	0
SERC	0.012	0.112	0.119	*	0	0	0
SPP	0	0	0	*	0	0	0

Table 3-8. Pumped Storage Projection

Regions	EIA Projected Increase (GW)			NERC LTRA Projected Increase (GW)[1]		Generation Interconnection Queue (GW)			
	PA	UPA	R	A	N	UC	Tier1	Tier 2	Tier 3
MISO	0	0	0	-0.032	-0.034	0.14	0.19	4.86	0
NPCC	0	0	0	0.066	0.07	0	0	0.6	0
PJM	0	0	0	0	0	0	0	0	0
SERC	0	0	0	0.182	0.194	0.42	0.42	0	0
SPP	0	0	0	0	0	0	0	0	0

Note: PA- Planned addition, UPA-Unplanned addition, R-Retirement, A-Available capacity during the hour of peak demand, N-Nameplate capacity, UC-Under construction,

1-The ratio of available capacity to nameplate capacity is assumed to be 0.94.

*- Information of under construction projects is not included in the interconnection queue

3.2.2.5.7 Key Findings

Through the comparisons of projections between different data sources, some key findings are concluded as follows,

- The projected increase of generation capacity is calculated as the difference between Year 2021 and Year 2025.
- The total peak load demand projection of NERC LTRA 2020 is close to the total load in the 2024 MMWG summer peak model, though differences exist in regional load forecasts. **The team decided to keep the load of 2024 MMWG summer peak model unchanged for the development of 2025 base case.**
- Both EIA and NERC projects coal retirements over the next 5 years. The major difference is that EIA AEO 2021 projects future retirements, while NERC LTRA 2020 only includes confirmed retirements. Additional retirements beyond what is reported as confirmed in the LTRA are expected and will continue to change the resource mix. Since generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated.
- EIA AEO 2021 and NERC LTRA 2020 presents different projections for natural gas-fired generation. The main reason is that EIA considers beyond Tier 1capacity additions and confirmed retirements. Another reason is the different category of natural gas-fired generation between EIA AEO 2021 and NERC LTRA 2020. EIA AEO 2021 contains two categories of generation related to natural gas: oil and natural gas steam, and combined cycle. Instead, NERC LTRA 2020 only include a single category for natural gas-fuel capacity. NERC LTRA 2020 also provides different projections from the interconnection queue, especially for MISO area. **The team determined the Tier 1 capacity additions using the interconnection queue and address confirmed retirements using Form EIA-860.**
- Both EIA AEO 2021 and NERC LTA 2020 give consistent projections for nuclear generation. **Information of the proposed nuclear plant at SERC and retirements in other regions are determined from Form EIA-860.**
- For renewable generation, EIA AEO 2021 provides more aggressive projections than NERC LTRA 2020 by considering more unplanned additions outside Tier 1 capacity. NERC LTRA reports on-peak

capacity, which is the available capacity during peak demand. Derating factors of on-peak capacity/nameplate capacity is provided in the NERC LTRA report for wind and solar resources by assessment area. In most regions, NERC LTRA projections are consistent with Tier 1 capacity in the interconnection queue, except for MISO, which needs further investigation. **The team decided to use Tier 1 capacity in the queue to build the 2025 base case.**

For conventional hydro and pumped storage projects, projected increase and retirements are minor in most regions. The team will use the interconnection queue information and Form EIA-860 to address the changes. A discussion of the derating of conventional run-of-river hydro generation subject to weather changes have been brought up to attention. Further investigation shows that derating have already been applied for existing units in the MMWG ERAG cases and only new additions may need adjustment.

3.2.2.6 Canadian Projections

To have another set of projections to juxtapose NERC projections for the Canadian areas, projections were also collected from Canada's 2020 Energy Futures (EF2020) report which is biannually published by the Canada Energy Regulator as part of its integrated energy analysis efforts [37]. The EF2020 report includes projected electricity capacity per fuel for Canada and its individual provinces through 2050 for two scenarios: a Reference scenario and an Evolving scenario. The main difference between the two scenarios is their underlying assumptions about crude oil prices and renewable energy costs affected by emission regulations and targets. The Evolving scenario is the primary scenario in the EF2020, it postulates that actions to reduce greenhouse gas (GHG) intensity continues to increase at current pace in Canada and the world. In contrast, the Reference Scenario assumes limited additional action to reduce GHG beyond the policies already in effect today, thereby implying that higher demand is still placed on fossil fuel than low carbon technologies in meeting growing demand [38].

Table 3-9 compare the 2025 projections for both CER and NERC for each NERC assessment region in Canada.

Table 3-9. Comparison of Generation projections by fuel for the Canadian regions of EI

Canadian Province (NERC region)	Source	2025 Nameplate Generation Capacity by fuel (GW)								
		Coal/ Coke	Gas	Nuclear	Hydro	Solar	Wind	Oil	Biomass/ Geothermal	Others
Manitoba (MRO-Manitoba Hydro [a])	CER (R/E)	0	0.403	0	6.049	0.053/ 0.093	0.258	0.0049	0.022	0
	NERC	0	0.42	0	6.09	0	0.31	0	0	0
New Brunswick + Nova Scotia + Prince Edwards Island (NPCC-Maritime [a,b])	CER (R/E)	1.587	0.752	0.705	1.376	0.069	1.227	1.986	0.243	0
	NERC	1.80	0.81	0.70	1.39	0	1.27	1.96	0.14	0.096
Ontario (NPCC-Ontario)	CER (R/E)	0	10.9/ 8.75	7.746	9.171	2.88/ 2.94	5.536	0.250	0.465	0
	NERC	0	9.11 [c]	7.92 [c]	8.37 [c]	0.478	4.84	2.62 [c]	0.29 [c]	0
	IESO	0	10.7 [d]	9.6	9.4	2.7	5.5	-	0.4 [e]	0
Quebec (NPCC-Quebec [a])	CER (R/E)	0	0.649	0	41.111	0.04/ 0.08	4.530	0.311	0.386/ 0.356	0
	NERC	0	0	0	42.72	0	4.84 [f]	0.52	0.44	0
Saskatchewan (MRO-SaskPower [a])	CER (R/E)	1.257	2.620/ 2.29	0	0.973	0.102/ 0.142	1.362/ 1.630	0.017	0.041	0
	NERC	1.33	2.48	0	0.92	0	1.192	0	0.0032	0.023

R – Reference Scenario, E – Evolving Scenario. Values are not repeated if they are the same for both scenarios.
[a] Winter peaking region.
[b] Excluding Northern Maine which is not in Canada. Northern Maine is a small portion of this region, so the projections are still expected to be comparable.
[c] Available on-peak to nameplate capacity ratio = IESO summer effective to nameplate capacity ratio
[d] Gas and Oil lumped together.

[e] Bioenergy projection including biomass, biogas, and waste.
[f] Available on-peak to nameplate capacity taken as 28% instead of the 2.8% in the NERC LTRA report which would have resulted into an inexplicably high nameplate capacity of 48.4 GW.
Notes:

- NERC reports available on-peak capacity which is generation capacity of a region during peak demand. To compare with CER nameplate values, corresponding NERC nameplate values were calculated using the estimated ratio of available on-peak capacity to nameplate capacity. These ratios are available in the NERC Long-term Reliability Assessment (LTRA) report for wind and solar resources [10].
- Available on-peak capacity to nameplate capacity for other resources were not provided in the NERC LTRA report. For Ontario, since it is the only Canadian region in EI that has an ISO (IESO), the available on-peak to nameplate capacity ratio for the other resources were calculated as the ratio of IESO summer effective capacity to nameplate capacity. A value of 94% was assumed as the available on-peak to nameplate capacity ratio for the other resources in the non-ISO regions.

The table above shows that NERC's projections are comparable to that of CER except in a few cases discussed as follows.

NERC's solar projections for the Canadian areas excluding Ontario are negligible. This is attributed to the winter peaking demand characteristics of these regions. Thus, available solar capacities at these winter peaks are negligible compared to their nameplate capacity. In Ontario where summer peak demand exists, the summer peak has reportedly moved later in the day due to increased penetration of distributed solar generation and the critical peak pricing program [10]. Hence, it is also reasonable that available on-peak solar generation become negligible compared to nameplate capacity.

There is also a large difference between the CER and NERC's projections for Ontario's oil-fired plants. This may be a classification complication raised by dual-fuel plants that use both oil and gas depending on availability, e.g., Lennox Generation station in Ontario. If gas and oil generation projections are lumped together like in the IESO APO report [29], the CER and NERC projections become more similar as shown in **Table 3-10**.

Table 3-10. Lumped Gas & Oil generation projection for Ontario

	Lumped Gas & Oil generation projections for Ontario (GW)
CER (R/E)	11.15/9.0
NERC	11.73

The large discrepancy between CER's biomass/geothermal projections in Saskatchewan compared to NERC's projections is difficult to explain since they are both dispatchable resources. NERC's projections are consistent at 3 MW for the two resource between 2021 and 2030 [10], but CER reports an increase from 31 MW to 46 MW over the same period [37]. Fortunately, they represent a minute proportion of the generation capacity mix for the region.

3.2.3 Development of 2025 EI Summer Base Case

After making the final decisions on generation additions, planned retirements, transmission expansion and upgrades that need to be addressed, the team has developed the power flow model and the dynamic model of the 2025 EI Summer Base Case. Details of the model development procedure are presented in this section.

3.2.3.1 Findings, Decisions and Conclusion

Through the abovementioned tasks, the team could provide the following findings, and conclusions:

Development of the power flow model and the dynamic model of 2025 EI Summer Base Case

1. The team has made the decision to integrate Tier 1 capacity additions sourced from generator interconnection queues of ISOs and utilities in the 2025 EI Summer Base Case. Tier 1 capacity

additions include projects that are under construction or have executed interconnection agreement (IA). Confirmed retirements sourced from EIA Form-860 [11] are also addressed in the 2025 model.

2. Capacity additions of queued renewable projects collected from individual ISOs and utilities are compared with the queue study carried out by Lawrence Berkley National Laboratory (LBNL) [39]. The list of queued projects provided by LBNL is used as a cross-check tool when project information collected by the team is incomplete.

3. Since POI information of new generation projects of Canadian regions are not available from public sources, no new projects are added and only confirmed retirements mentioned in the NERC LTRA 2020 report are addressed.

4. Converged power flow model of the 2025 EI Summer Base Case has been developed by integrating Tier 1 capacity additions and confirmed retirements. The power deficit/surplus caused by new generation additions and retirements are balanced regionally by scaling up/down the active power output of the in-service generators in the region. As a special case, DEV area provides a priority list of candidate generators that could be taken offline to accommodate the new generation additions. This list is used to replace conventional generators with renewable generation in the DEV area.

5. Fuel composition of both on-peak capacity and nameplate capacity are calculated by regions. Results show that natural gas is the dominant fuel source for electricity generation in the 2025 EI Summer Base Case.

6. Based on the power flow model of 2025 EI Summer Base Case, the team continues on the development of the dynamic model for future studies. Generic renewables models and default parameters are adopted for the newly integrated renewable projects. Dynamic models of new gas-fired generation are selected by referring to existing gas plants of similar size. A no-event flat run is implemented on the dynamic model of 2025 EI Summer Base Case and fluctuations of system variables are within acceptable range, which serves as a starting point for future dynamic studies.

7. The procedure of building the power flow model and the dynamic model of the 2025 EI Summer Base Case is scripted in Python and automated by the Python- Power System Simulator for Engineers (PSS/E) Application Program Interface (API).

Implementation of Transmission Expansion and Upgrades in EI

1. Due to the large number of proposed transmission upgrades in the EI region, the team decided to narrow the focus on baseline reliability projects since these have the highest probability of being implemented to ensure compliance with NERC standards and other regional reliability standards. For the extended PJM area, new transmission lines and line upgrades are included in the implementation plan. Furthermore, only new BES-level transmission line projects were selected for regions outside the extended PJM area, to only account for major topology changes in the network.

2. Using the above criteria, 43 transmission expansion and upgrades were selected for the extended PJM area, and 53 new transmission line projects were selected for the other areas.

3. For the line upgrade projects, only the line ratings were upgraded while their impedance characteristics were not changed. It was concluded that the variations in line impedances due to the upgrades were insignificant compared to the efforts required to perform impedance forecast for the upgraded lines.

4. Out of the total 43 selected projects, 36 were fully implemented, three (3) were partially implemented, and 4 were not implemented. Most of the projects that were not fully implemented were either partially or fully present in the original 2024 MMWG model. Only 2 projects and a portion of one were neither implemented nor already present in the model, mainly due to insufficient modelling information. Besides, 10 new transmission line projects outside the extended PJM area are added to power flow model.

5. The procedure of implementing transmission expansion in the extended PJM is scripted in Python and automated by the Python-PSS/E API such that transmission upgrades can be added or removed by simply modifying the accompanying csv files.

3.2.3.2 Development of power flow model of 2025 EI Summer Base Case

3.2.3.2.1 Generation additions and retirements

The team made the decision in Q1 to develop the 2025 EI Summer Base Case by integrating Tier 1 capacity additions and confirmed retirements. Information of Tier 1 capacity additions were collected from interconnection queues of individual ISOs and utilities. Confirmed retirements were sourced from EIA Form-860 [11]. The team investigated the newly published interconnection queue study by LBNL and used it to cross-check the previously collected queued projects. After determining the new generation projects and retirements, the power flow model of the 2025 EI Summer Base Case was developed in PSSE 34 based on 2024 MMWG summer peak model. The entire procedure was automated and scripted in Python.

3.2.3.2.2 LBNL Queue Study

LBNL published a study in May 2021 that synthesized data from transmission interconnection queues throughout the United States to illustrate trends in proposed power plants across time and regions. The study compiled and analyzed data from all seven ISOs/ Regional Transmission Operator (RTOs) in addition to 35 utilities not in ISO regions, representing an estimated 85% of all U.S. electricity load [39].

LBNL categorizes queued projects into active, withdrawn and completed projects. Active projects are further separated into projects that i) have executed interconnection agreement (IA) ii) are in the study phase and iii) have not started yet. Projects with executed IAs are considered as part of Tier 1 capacity additions. Projects that are already under construction are not included in the LBNL study.

To cross-check the previously collected queued projects using the LBNL study, a comparison of solar and wind capacity additions is shown in **Table 3-11**. The University of Tennessee Knoxville (UTK) column refers to the Tier 1 capacity collected by the UTK team, while the LBNL column refers to the capacity of projects that have executed IAs in the LBNL study. Since LBNL study does not consider under construction projects, for fair comparison, a third column is added which refers to the sum of LBNL projects and under construction (UC) projects collected by UTK team.

Table 3-11. Comparison of Tier 1 Capacity Additions

Tier 1	Wind/(MW)			Solar/(MW)		
Region	UTK[1]	LBNL[2]	LBNL+UC[3]	UTK	LBNL	LBNL+UC
Southeast Non-ISO	490	636	636	8657	6803	7028
SPP	11150	8920	8920	470	474	474
MISO	6516	0	5866	10430	220	9821
PJM	4631	2700	4631	7480	1015	7480
NPCC	2359	2200	2364	370	1632	1652

Notes: This table provides a comparison of combined Tier 1 capacity between UTK and LBNL queue study.
1- Tier 1 capacity from UTK Team. 2- Tier 1 projects from LBNL study, but under construction projects are excluded. 3- The numbers are the sum of LBNL and under construction projects identified from UTK side. 4- Differences between UTK and LBNL+UC result from the time that the queues are collected.

It can be noted from the table that for most regions, Tier 1 capacity additions of solar and wind generation are similar between UTK team and LBNL team. The disparities are most likely due to difference in time that queue information was collected, considering the interconnection queue is constantly updated. On the other hand, in Southeast non-ISO and SPP region, under construction projects are not explicitly labeled in the interconnection queue and therefore there is no difference between the LBNL and LBNL+UC columns. In these two regions, projects to be added are sourced from the interconnection queues of individual ISOs and utilities. Basically, the integrated queues provided by LBNL are used as a tool to cross-check the projects collected previously and modifications re made to the project lists if any projects were missing or added by mistake.

3.2.3.2.3 Changes reflected in 2025 EI Renewable Base Case

The power flow model of 2025 EI Summer Base Case was developed based on 2024 MMWG summer peak model by adding the determined new generation projects and removing confirmed retirements. **Table 3-12** shows a summary of the generation additions and retirements reflected in the 2025 EI Summer Base Case by region and fuel type. Since POI information of new generation projects of Canadian regions are not available from public sources, no new projects were added and only confirmed retirements mentioned in the NERC LTRA 2020 report [10] were addressed.

Table 3-12. Summary of generation additions and retirements by fuel type

Region	Renewable additions[1] (MW)	Gas additions[1] (MW)	Nuclear additions[1](MW)	Hydro additions[1](MW)	Coal retirements[1] (MW)	Gas/Oil Retirements[1](MW)
PJM	4540	8880	0	23	4408	0
SERC	5492	0	2200	0	991	332
SPP	2387	0	0	0	140	191
NPCC[2]	980	672	0	0	635	561
MISO	7859	0	-1457	119	17746	1527

Notes: 1. The values are the changes reflected in the 2025 EI Summer Base Case model compared to 2024 MMWG summer peak model. New generation projects have an expected in-service date after 2020. Capacity values are on-peak summer capacity. The derating ratios of the renewables are from Page 30, NERC LTRA 2020 [10], if not included in the interconnection queues. 2. NPCC area consists of New York ISO and ISO New England.

Table 3-13 shows a comparison of regional loads between NERC LTRA 2020 projections of 2025 and 2024 MMWG Summer Peak model. The projected total demand of 2025 is close to the existing loads in the 2024 MMWG model, therefore loads are not modified in the 2025 EI Summer Base Case.

Table 3-13, Comparison of load demands

Regions	NERC LTRA[1](MW)	2024 MMWG Summer Peak[2](MW)
FRCC	51,107	51,293
MISO	127,029	142,520
Manitoba Hydro	4,780	3,293
SaskPower	3,682	3,810
NPCC[3]	126,476	103,819
PJM	153,315	156,228
SERC[4]	136,964	138,990
SPP	55,082	59,891
Total	658,435	659,844

1- Data from NERC LTRA 2020 Report [10]. Numbers are projected total internal peak load demand of 2025, not including demand response. 2- Data from 2024 MMWG Summer Peak Model. Area grouping follows MMWG Procedural Manual. 3- NPCC region contains NPCC-Maritimes, NPCC-New England, NPCC-New York, NPCC-Ontario, and NPCC-Quebec. 4- SERC region covers SERC-C, SERC-SE and SERC-E

Figure 3-8 shows the fuel mix of installed on-peak and nameplate capacity of the 2025 EI Summer Base Case. On-peak capacity refers to the amount of capacity that a resource is capable of producing at peak demand. It can be concluded from the charts that natural gas will be the dominant fuel type for electricity generation of EI in 2025. Renewable generation from solar and onshore wind resources will take up a higher percentage of both on-peak capacity and nameplate capacity.

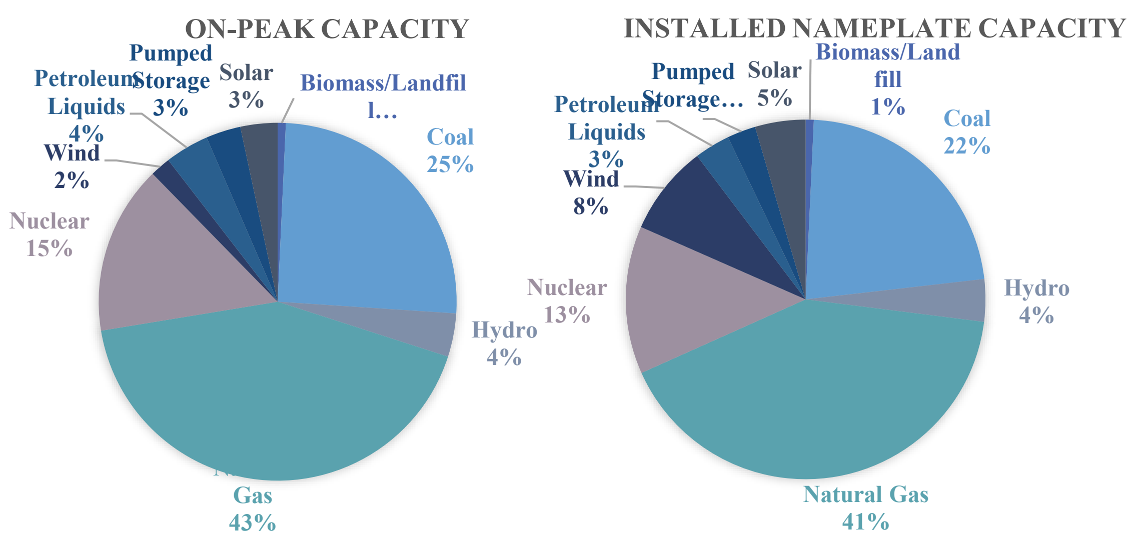


Figure 3-8. Fuel Composition of 2025 EI Renewable Base Case

The procedure of developing the power flow model of 2025 EI Summer Base Case is scripted in Python, using the PSS/E – Python API. Information of new generation projects and confirmed retirements, including point of interconnection and capacity, are stored in csv files by regions.

3.2.3.3 Development of dynamic model of 2025 EI Summer Base Case

For dynamic studies, generic model and default parameters are selected for the integrated renewables. Dynamic models of new gas-fired generation are selected by referring to existing gas plants of similar size. Dynamic model of utility-scale PV and wind plants in PSS/E consists of three modules: generator/inverter model, electrical control model and plant controller model. The connectivity diagram of the PV plant is shown in **Figure 3-9**.

- REGC module is used to model the generator/interface with the grid network. It processes the active and reactive current command from the electrical control module and outputs active and reactive current injection into the network.
- REEC module is used to model the electrical control part of the inverter. With the feedback of terminal voltage and generated power, it processes the active and reactive power reference from the plant controller and outputs active and reactive current command to the inverter module after limiting these commands with the current limit logic.
- REPC module is used to model the plant controller, which emulates active power control and volt/var control. It generates the power reference and outputs to the electrical control module

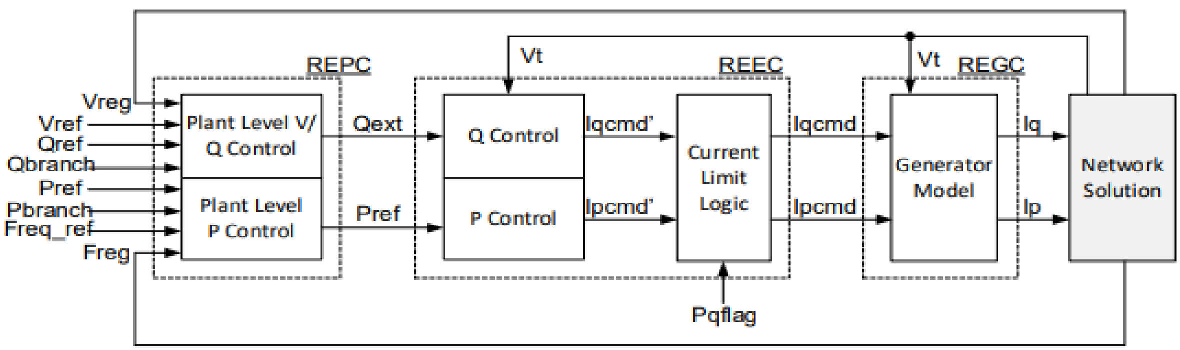


Figure 3-9. Connectivity diagram of the dynamic model of a generic PV plant

A no-event flat run is implemented on the dynamic model of 2025 EI Summer Base Case. Bus frequency at 500kV buses is monitored and plotted in **Figure 3-10**. The deviations are within acceptable range, which serves as a starting point for future dynamic studies.

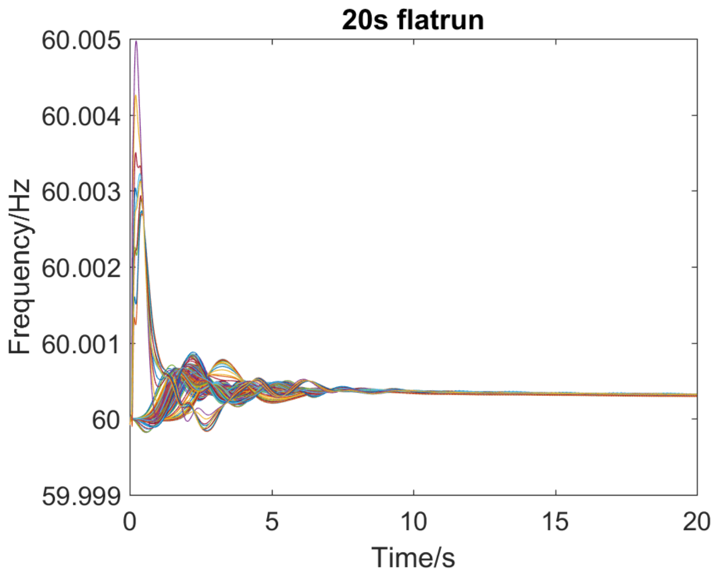


Figure 3-10. Flat run of 2025 EI Summer Base CASE

3.2.3.4 Implementation of the Transmission Expansion Plan in the Extended PJM area

A total of 43 transmission expansion and upgrade projects are selected to be added to the extended PJM area of the 2025 EI Summer Base Case as shown in **Table 3-14**. Furthermore, some project categories have been updated as more information about the projects are acquired.

Table 3-14. Updated list of selected baseline reliability transmission projects for the extended PJM area

	S/N	Project Category	Brief Project Description	Expected Date In-Service
Previously Reported	1	New Line	69 kV line from Armstrong Cork to Jay SS	Jun 2022
	2	New Line	Install 2nd 230 kV circuit lines between Lanexa and Northern Neck SS	Jun 2023
	3	New Line	Extend a single circuit lines 230-kV line from Farmwell to Nimbus SS	Jun 2025
	4	New Line + Line Upgrade	Extend 230 kV Cannon Br.-Clifton line to Winters Br.	Jun 2023
	5	New Transformer	Install 2nd Chickahominy 500/230 kV transformer	Jun 2023
	6	Voltage Upgrade	Convert 34.5 kV Gateway-Wallen circuit to 69 kV	Mar 2022
	7	Voltage Upgrade + Line Upgrade	Convert 115 kV Liberty-Lomar and Cannon Br.-Lomar circuits to 230 kV	Jun 2023
	8	Voltage Upgrade + Line Upgrade	Convert 34.5 kV East Leipsic-New Liberty circuits to 138 kV	Jun 2025
	9	New Volt-Amps Reactive (VAR) support	Add 7.2 MVAr fixed cap. Bank on Lock Haven-Reno & Flemington 69 kV lines	Jun 2025
	10	New VAR support	Add 10 MVAR 69 kV capacitor bank at Swainton substation	Jun 2025
	11	New VAR support	Install 2nd 138 kV, 28.8 MVAR capacitor with switcher at Enon SS	Jun 2025
	12	New VAR support	Install a 34 MVAR 115 kV shunt reactor on Rockwood-Mayersdale line	Jun 2025
	13	New VAR support	Add 100 MVAR reactor bay at Tangy SS	Jun 2025
	14	New VAR support	Install a 75 MVAR Reactor at Broadview SS	Jun 2025
	15	New VAR support	Install two 46 kV 6.12 MVAR capacitor at Mt. Union SS	Jun 2025
	16	New VAR support	Install 138 kV, 36 MVAR capacitor at Baker SS	Jun 2025
	17	New VAR support	Add two 36 MVAR capacitors at the Stonewall 138 kV SS	Jun 2025

	S/N	Project Category	Brief Project Description	Expected Date In-Service
	18	New VAR support	Install 2nd 125 MVAR 345 kV shunt reactor at Pierce Brook SS	Jun 2025
	19	New VAR support	Install 2nd 115 kV, 33.67 MVar cap bank at Harrisonburg SS	Dec 2025
	20	New SS + Transformer	Build new 230 kV Stevensburg SS with a 224 MVA, 230/115 kV transformer	Jun 2024
	21	New Line + SS + Transformer	New 138 kV line extension to connect Lake Head to the 138 kV network and 138/69 kV transformer.	Jun 2024
	22	New Line + SS + Transformer	Build new AMPT 138/69 kV substation, with a 138/69 kV 130 MVA transformer, and a 138 kV line between Brim SS and the new SS	Jun 2024
	23	New Line + Transformer	Install a 2nd 138/34.5 kV transformer at Dragoon SS and a 138 kV conductor along the other side of Dragoon Tap 138 kV line	Jun 2025
	24	New SS + VAR support	Build a switching station at the junction of 115 kV lines #39 and #91 with a 115 kV capacitor bank.	Dec 2025
New Additions	25	Line Upgrade	Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR	Jun 2025
	26	Line Upgrade	Rebuild 69 kV line from Rob Park to Harlan	Jun 2025
	27	Line Upgrade	Rebuild 69 kV line section from Norwood to Shopville 69 kV using 556 ACSR	Dec 2021
	28	Line Upgrade	Rebuild 69 kV line between Newcomerstown and Salt Fork Switch with 556 ACSR	Jun 2025
	29	Line Upgrade	Rebuild 69 kV line from Kammer Station to Cresaps Switch	Jun 2025
	30	Line Upgrade	Rebuild 69 kV line from Cresaps Switch to McElroy Station	Jun 2025
	31	Line Upgrade	Rebuild from Colombia Carbon to Columbia Carbon Tap 69 kV	Jun 2025
	32	Line Upgrade	Rebuild 69 kV line from Lancaster to South Lancaster with 556 ACSR conductor	Jun 2025
	33	Line Upgrade	Rebuild 69 kV line between Lancaster Junction and Ralston station	Jun 2025
	34	Line Upgrade	Rebuild 69 kV line between East Lancaster Tap and Lancaster	Jun 2025
	35	Line Upgrade + VAR Support	Rebuild Bradley to Scarbro 46 kV line using 795 ACSR and 69 kV standards, and install new 12 MVAR capacitor bank at Bradley station	Jun 2021
	36	Line Upgrade	Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV line	Jun 2023
	37	Line Upgrade	Reconductor the Mt. Pleasant to Middletown Tap line	Jun 2025
	38	Line Upgrade	Reconductor the 500 kV line section from Doubs to Goose Creek using 3-1351.5 ACSR 45/7	Jun 2025
	39	Line Upgrade	Reconductor 230 kV line #2172 from Brambleton to Evergreen Mills to achieve summer emergency rating of 1574 MVA	Jun 2025
	40	Line Upgrade	Reconductor 230 kV line #2210 from Brambleton to Evergreen Mills to achieve summer emergency rating of 1574 MVA	Jun 2025
	41	Line Upgrade	Reconductor 230 kV line #2213 from Cabin Run to Yardley Ridge to achieve a summer emergency rating of 1574 MVA	Jun 2025
	42	Line Upgrade	Reconductor 230 kV radial line #242 from Midlothian to Trabue junction to allow a minimum summer rating of 1047 MVA	Jun 2025
	43	Line Upgrade	Reconductor the Wilson-Mitchell 138 kV circuit	Jun 2021

Out of the 43 selected projects, four (4) projects are not implemented and three (3) are partially implemented due to the reasons presented in the table below. The serial numbers in **Table 3-15.** are retained for cross-referencing.

Table 3-15. Projects not implemented or partially implemented

S/N	Project Category	Reasons for non-implementation or partial implementation
1	New Line	Upgrade is already in the 2024 MMWG model
3	New Line	Nimbus terminal was not found in the 2024 MMWG model and required information to create it was not available
4	New Line + Line Upgrade *	New line portion is already in the 2024 MMWG model, only line upgrade was implemented

8	Voltage Upgrade + Line Upgrade *	Voltage upgrade portion was not implemented because the terminals are connected to several other buses without a transformer interface. Hence, only line upgrade was implemented
24	New SS + VAR support*	New substation is already in the 2024 MMWG model, only VAR support was added
41	Line Upgrade	Cable Run terminal was not found in the 2024 MMWG model and required information to create it was not available
43	Line Upgrade	Upgrade is already in the 2024 MMWG model

*Partially implemented project

Therefore, 36 projects are fully implemented and the line upgrade portions of projects #4 and #8 along with the new Volt-Amps Reactive (VAR) support of project #24 were implemented. Only projects #3, #41 and a portion of #8 are neither implemented nor already- present in the original model. **Figure 3-11** summarizes the upgrades added to the 2024 MMWG model for the implementation of the 2025 EI Summer Base Case transmission expansion plan. Note that the total number of upgrades is larger than the number of implemented projects because some of them involved multiple upgrades.

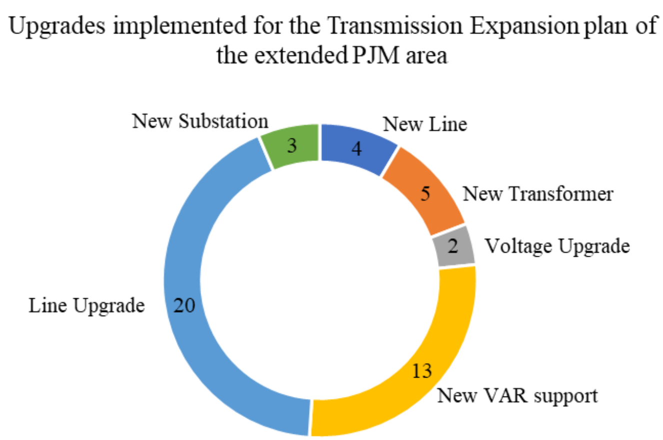


Figure 3-11. Upgrades involved in the extended PJM area Transmission Expansion plan

To apply the upgrades to the PSS/E file of the 2024 MMWG model, the PSS/E – Python API is used. The Python code is connected to three .csv files which contain relevant data needed to implement some of the upgrades, thus allowing for addition and/or removal of upgrades by simply modifying the csv files. Upgrades that can be adjusted using this method include voltage upgrade, line upgrade, new lines, and addition of new VAR support. Others such as addition of new transformers and new substation which usually involve some parameter tuning or stepwise solution can only be adjusted by editing the Python code itself.

3.2.4 Grid strength Study of 2025 EI Summer Base Case

Grid strength describes the stiffness of terminal voltage in response to current injection variations. In a strong grid, voltage and angle are relatively insensitive to variations of current injections [40]. The control systems of IBRs rely on the voltage magnitude and angle at their terminals to not be largely affected by the injections from the resource for stable operation. Therefore, it is significant to ensure adequate grid strength as the penetration of the renewables increase.

Grid strength is closely related to short circuit current level. Normally, the higher the short circuit level, the stronger the grid. Different from synchronous units that could provide short circuit current many times the rated current, IBRs provide no substantial contribution to short circuit current due to the technical limitations of the inverters. As more synchronous units are replaced by IBRs, a decrease in short circuit level is expected, which increases the risk of voltage instability and voltage collapse. Therefore, it is of significance to monitor grid strength, identify weak grid conditions and develop mitigation strategies as the grid transitions towards the carbon-free goal.

This section presents the results of grid strength studies using 2025 EI Summer Base Case. The studies utilize existing metrics for grid strength quantification. In addition, the team also investigates the weak grid issues that could arise under weak grid conditions and explores new indicators for monitoring grid strength.

3.2.4.1 Findings, Decisions and Conclusion

Through the abovementioned tasks, the team could provide the following findings, and conclusions:

Short circuit analyses

1. The team implemented short circuit analyses of Dominion Energy Virginia (DEV) territory using the developed power flow model of 2025 EI Summer Base Case. Short Circuit MVA (SCMVA) values are calculated at different voltage levels within the area and results are compared among 2021 MMWG summer peak model, 2025 EI Summer Base Case and 2025 sensitivity case. There is a decrease of SCMVA identified in the 2025 case over 115kV and in the 2025 sensitivity case at all voltage levels. This could be explained by the replacement of conventional machines with IBRs, which provide no substantial contribution to fault current.

2. The team implemented short circuit analysis in PJM area. Minimum SCMVA at different voltage levels are compared between the 2021 MMWG summer peak model and 2025 EI Summer Base Case. Further investigations are carried out in areas that have a significant decrease in minimum SCMVA.

3. The team investigated potential weak grid conditions in the 2025 case, which could have a significant impact on the stable operation of IBRs. Grid strength are estimated at various locations in the 2025 case using short circuit ratio (SCR) based metrics.

4. The application of SCR-based metrics in identifying weak grid issues have some limitations. Low grid strength issues are typically site-specific, which makes it difficult to establish strict threshold for SCR-based metrics in determining weak grid conditions. Lower SCR typically indicates a higher risk of weak grid issues but could not predict the mode of failure or the precise point where system stability will be compromised. It is recommended that SCR-based metrics be used as a high-level screening tool and further detailed studies are needed to determine whether weak grid issues will occur under the identified weak conditions.

Voltage impact studies

1. The team carried out voltage impact studies using the developed 2025 case. Bus voltages under balanced fault conditions are simulated at different fault locations. The team identifies voltage violations under balanced fault conditions based on CBEMA (Computer Business Equipment Manufacturers Association)/ITIC (Information Technology Industry Council) curve, which defines the normal and abnormal operating voltage for IT equipment in terms of magnitude and duration of

the voltage events. The team discovered that the severity of the fault event is related to the SCMVA at the fault location, but SCMVA may not be a direct indicator.

2. The team studied the short circuit current contribution from generator at different locations. It is observed that most of the contribution are made by generators close to the short circuit location. The contribution is closely related to the electrical distance from the short circuit location. A threshold of electrical distance could be established as a cutoff point, beyond which the short circuit current contribution could be negligible.

3. The team studied the impact of grid strength on Fault-Induced Delayed Voltage Recovery (FIDVR) events. 70% of the active power load inside DEV territory are modeled as composite loads. Study results show that as more synchronous units are replaced by renewables and grid strength decreases, bus voltages have a more delayed recovery during FIDVR events.

4. The team identified conventional plants that are critical for maintaining grid strength in DEV area. Two criteria are selected to quantify the importance of each plant. One is the average SCMVA contribution to regional grid strength. The other is the impact on voltage response, which is characterized as the largest time delay in voltage recovery caused by the replacement of the considered conventional plant with renewables. The identified critical plants could provide recommendations for the decision-making of the retirements of these plants as the grid transitions toward the carbon-free goal.

3.2.4.2 SCMVA analysis

The team implemented short circuit analyses of DEV territory using the developed power flow model of 2025 EI Renewable Base Case. To show the contribution of the synchronous units to short circuit current level, the team also creates a 2025 sensitivity case based on the 2025 EI Summer Base Case, in which the existing coal and gas plants within DEV area are replaced by renewables. SCMVA values are calculated at different voltage levels within the area and results are compared between 2021 MMWG summer peak model, 2025 EI Summer Base Case and the 2025 sensitivity case. The comparison of average SCMVA values within each voltage level is shown in **Table 3-16**.

Table 3-16. Comparison of average SCMVA

kV	Average SCMVA		
	2021 Summer	2025 Summer	2025 Sensitivity
69	1444.8	1683.7	1650.4
115	2338.3	2383.0	2343.7
138	1901.1	1812.7	1798.8
230	9074.4	8951.4	8266.6
500	23331.5	21763.3	18377.7

It can be concluded that compared to the 2021 summer peak case, the 2025 base case shows a reduction in average SCMVA over 115kV, with around 7% drop within 500kV buses. This could be explained by the replacement of conventional machines with IBRs and the retirements of several coal plants, which contribute to lower short circuit current level. It is worth mentioning that there are also several major gas plants that are integrated in the 2025 base case. These new synchronous plants could also contribute to the SCMVA level in local area. As more synchronous units are replaced by renewables in the 2025 sensitivity case, SCMVA level continues to drop at all voltage levels, with a nearly 20% drop within the 500kV buses compared to the 2021 base case. The team also calculates the average SCMVA only considering contribution from inside DEV area, as shown in **Figure 3-12**. The results show similar trend as in Table

17. This indicates that as the grid approaches the carbon-free goal, it is important to monitor the short circuit level of the system and develop mitigation strategies to maintain adequate grid strength.

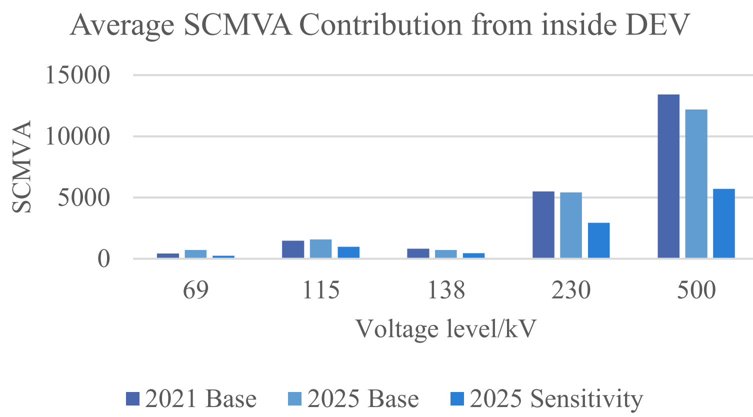
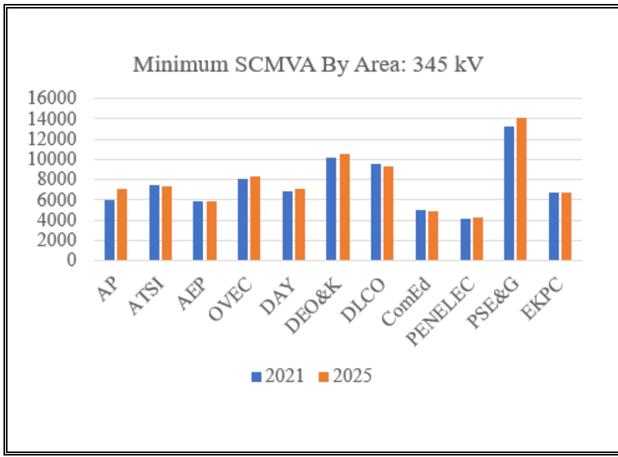


Figure 3-12. Average SCMVA contribution from inside DEV

The team carried out short circuit analysis for the entire PJM area. Minimum SCMVA at 345 kV and 500kV are compared among different regions, as shown in **Figure 3-13**. The minimum SCMVA at some areas are lower in the 2025 case due to the retirements of conventional generation in the area.



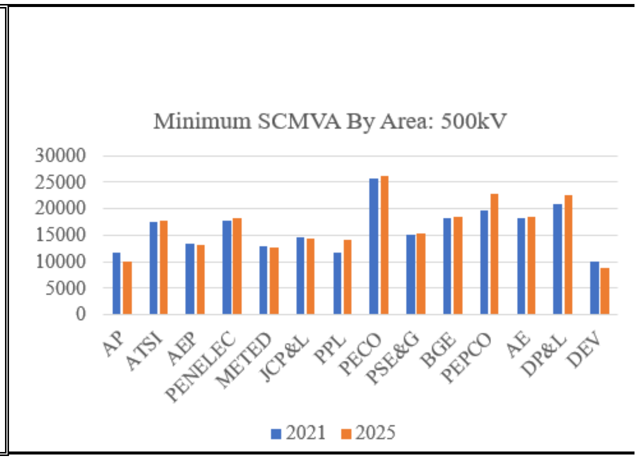


Figure 3-13. Minimum SCMVA By Area

3.2.4.3 Short Circuit Current Contribution region

Apart from the SCMVA analysis, the team also carried out a study on decomposing the short circuit current contribution from different generators.

Figure 3-14 shows the distribution of short circuit current contribution when the short circuit location is at one of the 500kV bus location in DEV area. Only generators with higher than 0.1% contribution of the total short circuit current are plotted and generators with larger than 1% contribution are marked as dark red color. Several observations could be made from the figure. First, generators closer to the short circuit location have a much higher contribution to the total short circuit current. In addition, though individual generator outside DEV area has a relatively lower contribution, the aggregating effects from these generators (outside DEV) as a whole are still non-negligible.

The team studied the relationship between the short circuit contribution and the electrical distance from the short circuit location to the generator terminal, as shown in **Figure 3-15**. The team provided the suggestion that 1 per unit of electrical distance could be a cutoff point, beyond which the short circuit current contribution could be negligible.

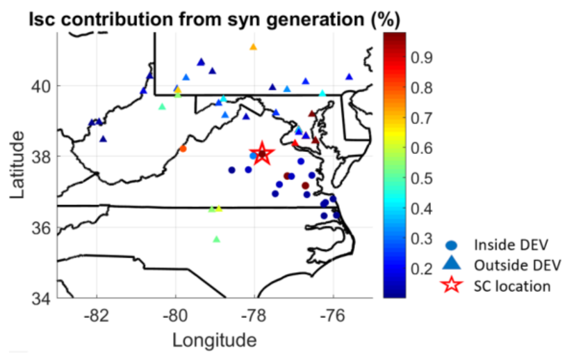


Figure 3-14. Distribution of Isc contribution

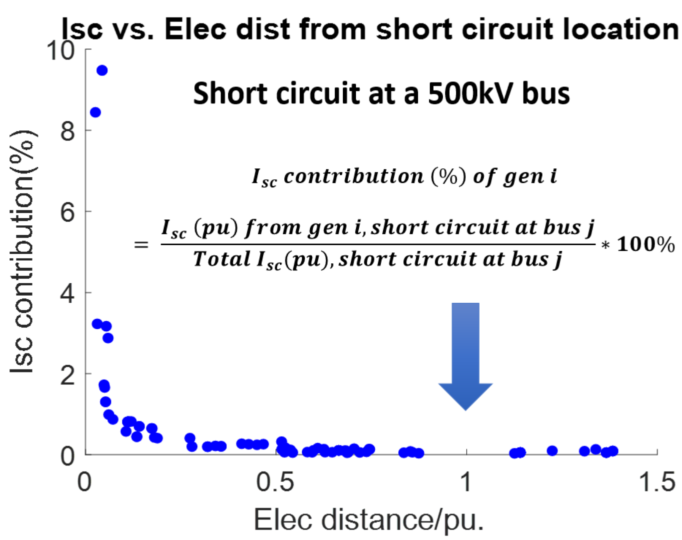


Figure 3-15. Isc vs. Electric distance from short circuit location

3.2.4.4 Short Circuit Ratio (SCR) based metrics

3.2.4.4.1 Short Circuit Ratio (SCR)

SCR is the mostly used metric to quantify grid strength. It is defined as the ratio of short circuit MVA at the POI location from a three-phase line-to-ground fault to the MW output of the IBR connected to the POI, as shown as:

$$SCR = \frac{SCMVA_{POI}}{MW_{IBR}}$$

$SCMVA_{POI}$ is the SCMVA level at the POI without contribution of IBRs, MW_{IBR} is MW output of the IBRs connected at the POI. SCR is more suitable to quantify grid strength when only considering a single

IBR. A lower SCR represents relative lower grid strength at the POI location. It does not account for the interaction between multiple IBRs that are closely connected [40]. Therefore, SCR could give over-optimistic estimates of grid strength.

3.2.4.4.2 Weighted Short Circuit Ratio (WSCR)

WSCR was initially proposed in the Texas Panhandle Region study [41] to account for the interaction between IBRs that are electrically close. WSCR is defined as:

$$WSCR = \frac{\sum_i SCMVA_i * P_i}{(\sum_i P_i)^2}$$

$SCMVA_i$ is the SCMVA level at bus i, P_i is the MW rating of the IBR connected at bus i.

The calculation of WSCR requires the selection of a group of closely connected IBRs. To determine the cluster of IBRS that are electrically close, electrical distances between different POIs can be calculated using system impedance matrix.

$$dist_{ij} = Z_{ii} + Z_{jj} - 2Z_{ij}$$

$dist_{ij}$ is the electrical distance between bus i and j, Z is system impedance matrix.

WSCR assumes full interaction between IBRs within the defined group. All IBRs within the group are assumed to be connected at a virtual POI location. However, in real operations, there is some electrical distance between IBRs.

3.2.4.4.3 Short Circuit Ratio with Interaction Factor (SCRIF)

SCRIF is proposed to capture the change in bus voltage at one bus resulting from a change in bus voltage at another bus. This sensitivity is defined as the interaction factor (IF) between two buses. Buses that are electrically closer have a higher interaction factor. IF could be estimated by the manipulation of system impedance matrix. SCRIF is defined as:

$$SCRIF_i = \frac{SCMVA_i}{P_i + \sum_j IF_{ji} * P_j}$$

$SCMVA_i$ is the SCMVA level at the level, P_i is the MW rating of the IBR connected at bus i. IF_{ji} is the interaction factor between bus i and j. It is defined in (5). Different from WSCR, SCRIF integrates the electrical distance between multiple IBRs into equation. Therefore, there is no need to identify a group of closely connected IBRs at first.

$$IF_{ji} = \frac{\Delta V_j}{\Delta V_i} = |\frac{Z_{ij}\Delta I_i}{Z_{ii}\Delta I_i}| = |\frac{Z_{ij}}{Z_{ii}}|$$

3.2.4.4.4 Study results

To quantify grid strength and identify potential weak grid conditions, different SCR-based metrics are applied at the renewable POIs in the DEV area. A comparison of SCR and SCRIF metrics at renewable POIs is shown in **Figure 3-16**. Since SCR only considers the single inverter that is connected POI, it gives a much more optimistic estimate of grid strength, with a minimum of SCR of 16.33. On the contrary, SCRIF accounts for the interaction between multiple IBRs based on their electrical distance to each other. SCRIF provides a more conservative estimate, with a minimum SCRIF of 4.92.

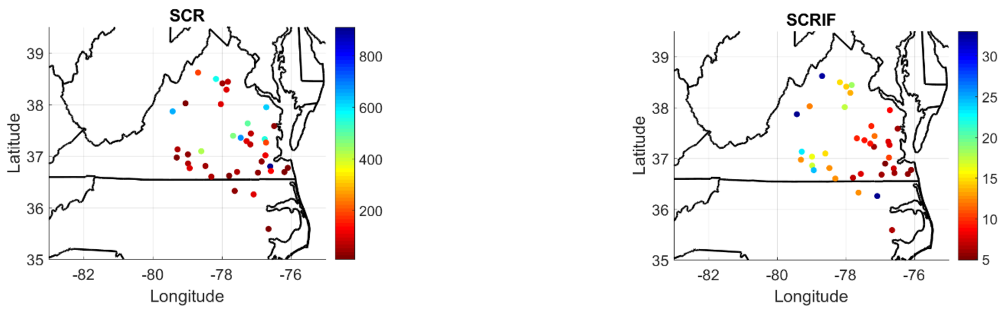


Figure 3-16. SCR and SCRIF

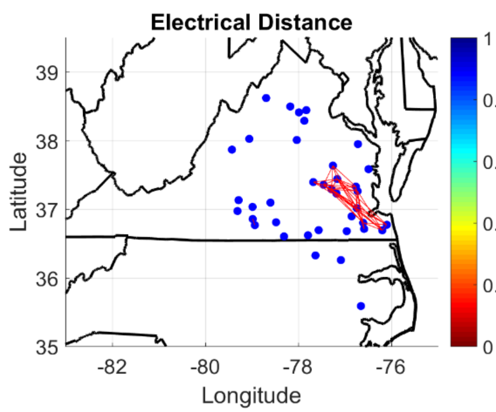


Figure 3-17. Clustering for WSCR calculation

As for estimate using WSCR, a plot of an identified cluster using electrical distance metric is shown in **Figure 3-17**. The shortest 50 connections between the POI buses are shown, represented by the red lines. Considering the buses that are connected by the red lines as a cluster, an estimated WSCR is derived as 5.12. The location of the cluster identified by the electrical distances is similar to the red dots shown in the SCRIF plot, partly because electrical distance measure between IBRs is considered in both metrics. However, how to define the electrically close IBRs in WSCR calculation still requires further studies.

The three metrics applied give different estimates of grid strength at the renewable POIs within DEV area, due to the different assumptions that they are based on. In the Texas Panhandle study, a WSCR of 1.5 is determined as the threshold of system strength for the Panhandle region. However, it is very difficult to establish a strict threshold for the SCR-based metrics since the estimate of grid strength is normally system-specific and site-specific, which makes it unreasonable to apply the same threshold over a wide area. Lower SCR typically indicates a higher risk of weak grid issues but could not predict the mode of failure or the precise point where system stability will be compromised. It is recommended that SCR-based metrics be used as a high-level screening tool and further detailed studies are needed to determine whether weak grid issues will occur under the identified weak conditions.

3.2.4.5 Voltage impact studies using 2025 EI Summer Base Case

Apart from using the SCR-based metrics as a high-level screening tool for identifying potential weak grid conditions, the team also conducted studies of the impacts of grid strength on system voltage performance after fault events. Related results are presented in this section.

3.2.4.5.1 Voltage dynamics under three-phase line-to-ground faults

The team carried out fault voltage studies within DEV territory using 2025 EI Summer Base Case. Three-phase line-to-ground faults, cleared after four cycles, are simulated at different locations (buses at 115kV and over) within DEV area. A colormap that depicts the fault-on bus voltages at different geographical locations is shown in **Figure 3-18**. The black star denotes the fault location. It can be observed that the simulated fault could cause relatively low voltage in local regions near the fault location.

To identify voltage violations during fault events, CBEMA/ITIC curve, as shown in **Figure 3-19**

Figure 3-19, is used to evaluate the voltage dynamics at load buses. CBEMA/ITIC curve defines a no-interruption region by assigning the tolerable time duration for different voltage magnitude.

Using the CBEMA/ITIC curve, buses that falls out of the no-interruption region are identified as violations. **Figure 3-20** shows an example of the operating points of monitored buses after a fault event. Each blue dot represents the operating point of the monitored bus. The coordinates of the dot give the information of the magnitude of the voltage dip and its duration at the monitored bus.

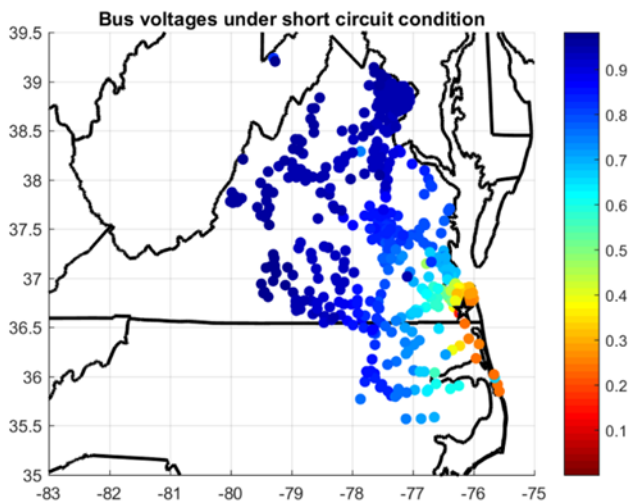


Figure 3-18. Fault-on bus voltages

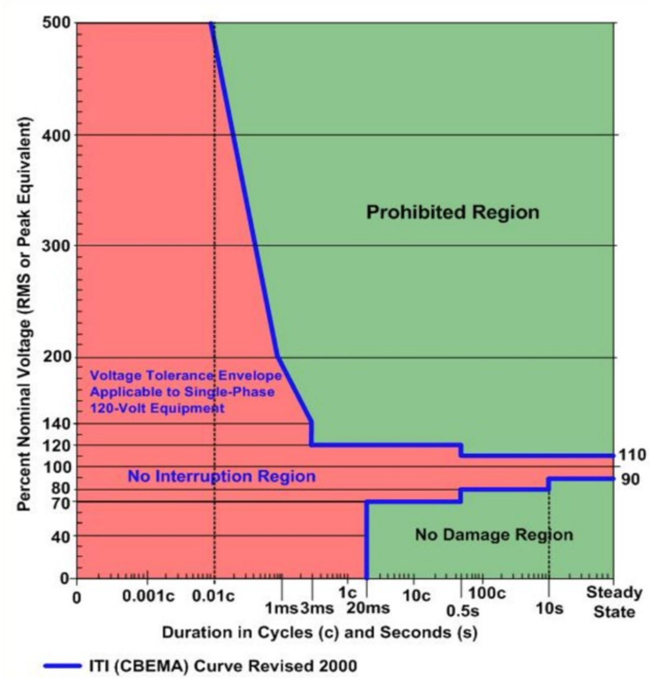


Figure 3-19. CBEMA/ITIC curve

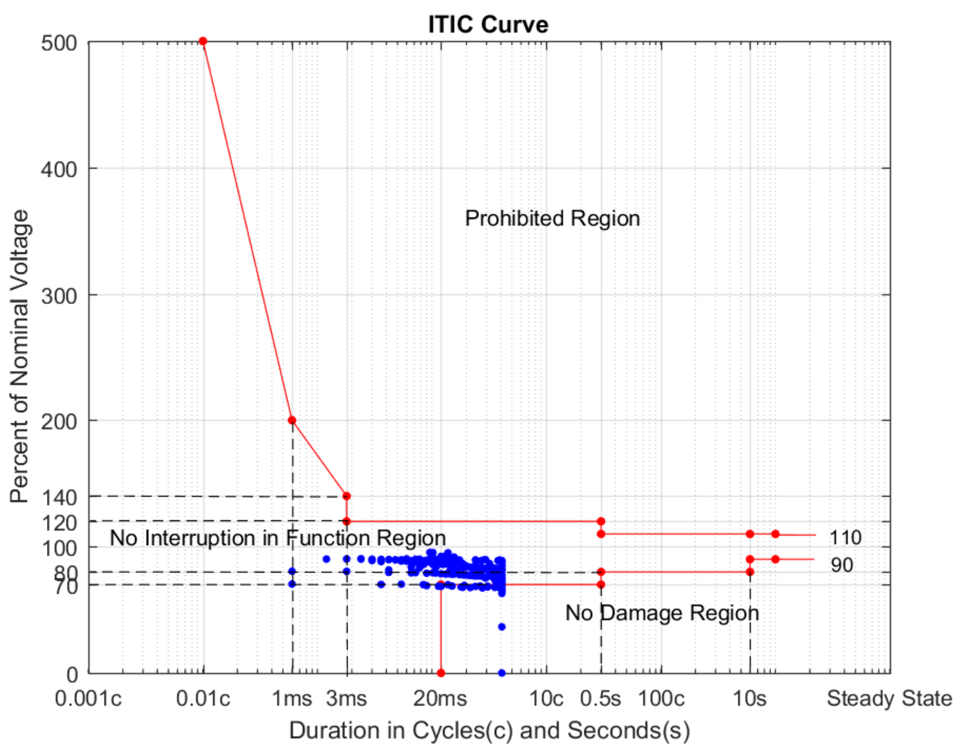


Figure 3-20. Operating points of monitored buses after a fault event

In addition, the relationship between the number of violations based on CBEMA/ITIC curve and SCMVA at the fault location is studied, as shown in **Figure 3-21.**

Figure 3-21The scatter plot shows that there is some correlation between the SCMVA and the number of violations. However, the relationship, the higher the SCMVA at the fault location, the more violations, is not quite straightforward. A possible explanation could be that locations with higher SCMVA values are relatively more closely connected to large synchronous units, therefore fault events at these locations have more severe consequences. In a nutshell, the SCMVA index at the fault location may not be directly used as an indicator for the severity of the fault event.

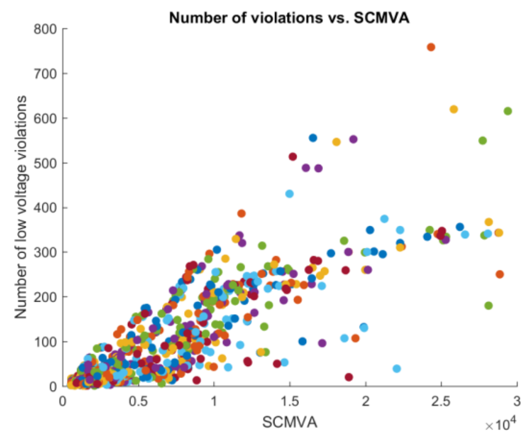


Figure 3-21. Number of violations vs. SCMVA

3.2.4.5.2 Fault Induced Voltage Delayed Recovery (FIDVR) event

The phenomenon that system voltage remains at excessively low levels for a duration of several to tens of seconds after fault clearing is considered as FIDVR event. FIDVR events are usually caused by a large percentage of single-phase induction motor loads with constant torque characteristics that will stall when system voltage dips to lower levels. This type of loads consumes a large amount of reactive power from the grid and will draw 5-6 times their steady state current in the stalled condition, which will lead to the delayed voltage recovery and even voltage collapse.

To study the FIDVR events in the projected 2025 scenario, the team added composite load models for 70% of the total active power load within the DEV area. The structure of the composite load model used in shown in **Figure 3-22**.

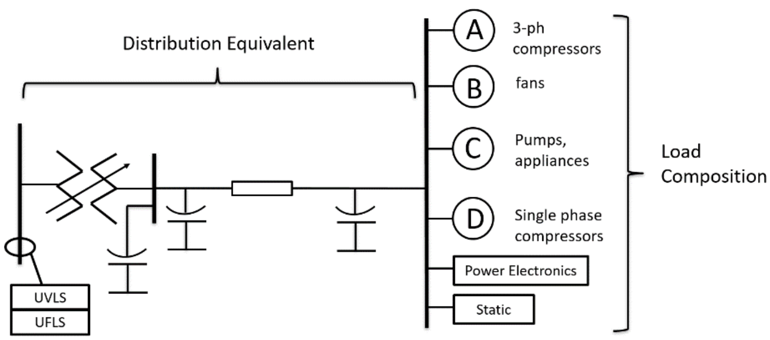


Figure 3-22. Composite load structure

Bus voltages under balanced three-phase line-to-ground fault conditions are simulated with different locations in the DEV area. The NERC Protection & Control (PRC)-024-2 Standard [42] that defines generator ride-through capability under voltage excursion events is used to identify violations. The 'no-trip' zone is considered as the safe operating region for generators and is shown in **Figure 3-23**.

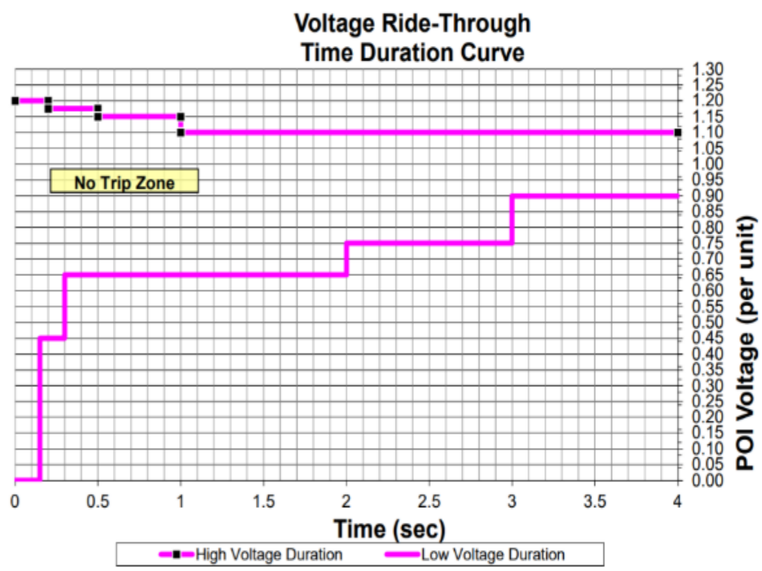


Figure 3-23. NERC PRC-024-2 generator ride-through capability

A comparison of the generator terminal voltage dynamics after a fault event between the 2025 base case and the 2025 sensitivity case is shown in Error! Reference source not found..

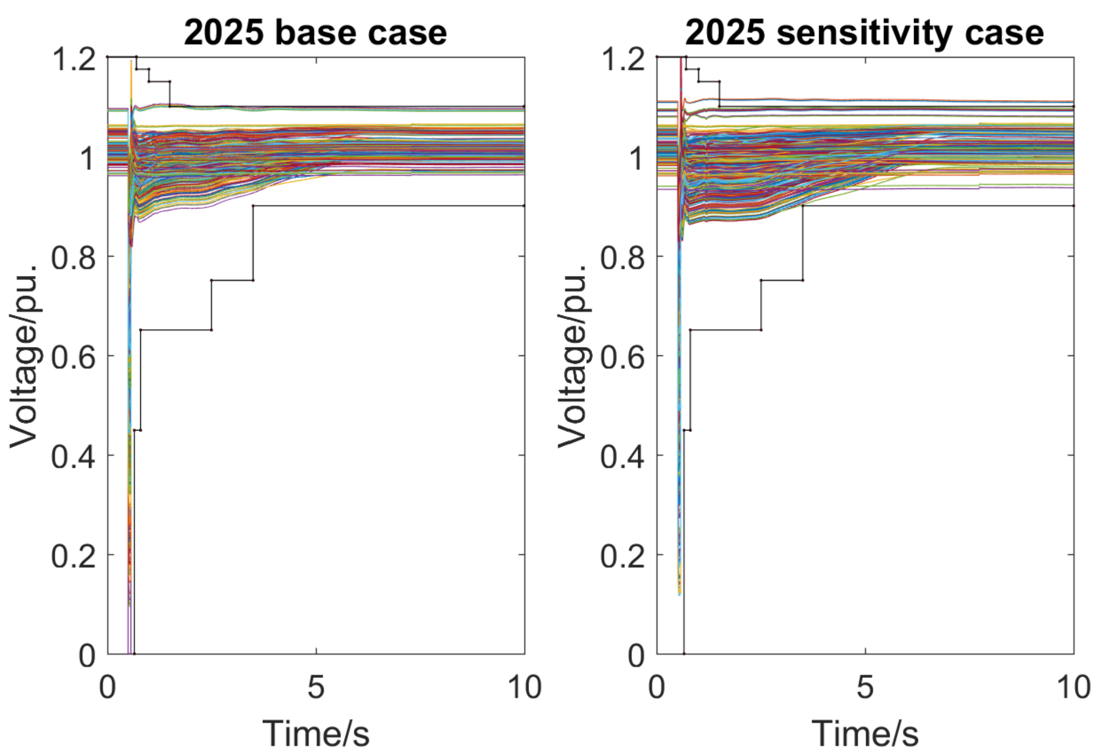


Figure 3-24. Comparison of generator terminal voltage dynamics after a fault event between the 2025 base case and the 2025 sensitivity case

Error! Reference source not found.The 2025 sensitivity case is developed based on the 2025 base case by replacing the existing coal and gas plants in DEV area with renewables, which leaves fewer synchronous unit online and result in lower grid strength. It can be observed from the figure that in both cases generator terminal voltage does not fall below the lower boundary of the 'no-trip' zone defied by NERC PRC-024-2 Standard. However, it is obvious that as grid strength decreases in the 2025 sensitivity case, voltage responses are closer to the boundary, which may lead to the tripping of some units and even cascading events. It can be concluded from this study that as the penetration of renewables increases and grid strength decreases, generators could have more difficulty in maintaining ride thorough capability during FIDVR event and mitigation strategies may be needed to ensure adequate grid strength.

3.2.4.5.3 Critical plant identification

As the power grid approaches the carbon-free goal, fossil-fueled conventional generation will be retired and replaced by renewables. However, during this transition, it is important to ensure adequate grid strength for the stable operation of IBRs and the reliability of the grid. Therefore, it is necessary to identify conventional plants that critical for grid strength. Recommendations could be provided for the decision making of preserving or delaying the retirements of these plants.

In this section, critical plants were identified within DEV area from different perspectives. First, importance of each plant to grid strength is quantified as its average short circuit current contribution to the area. For each plant, the average short circuit current contribution is calculated by averaging its contribution to SCMVA at all bus locations in DEV area. The second measure is from the perspective of voltage dynamics. As observed in the FIDVR study, voltage recovery could be more delayed under lower grid strength conditions. Therefore, the team proposed to use time delay in voltage recovery T_{delay} to quantify the impact of conventional plant on voltage recovery. An example is shown in **Figure 3-25**. A threshold of 0.95 is established to determine the time delay in voltage recovery. To quantify the impact of each individual plant on voltage recovery, the maximum T_{delay} over all DEV buses after replacing the plant with renewables is selected as a metric for the importance of the plant.

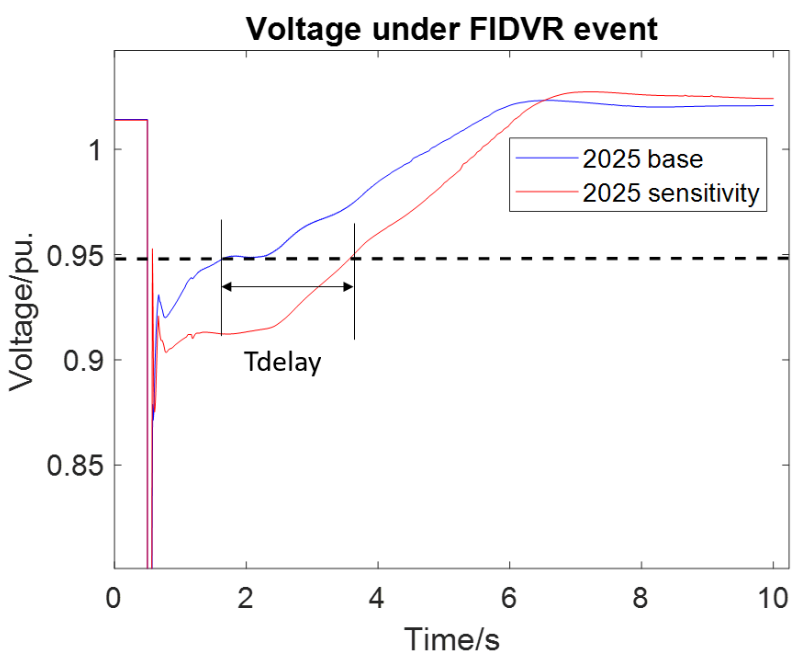


Figure 3-25. Definition of Tdelay

The critical plants identified from the two abovementioned perspective is shown in **Table 3-17**. Top 5 critical plants are labeled as red. It can be observed from the table that most of the identified critical plants are the same using two different criteria. Since voltage dynamics are affected by fault location, the critical plants identified using T_{delay} metric could also be affected by location of the fault event that is selected for the identification procedure.

Table 3-17. Critical plant identification

Plant No.	Type	MBase/MW	Isc contribution/pu.	Largest T_{delay}/s
1	Gas	1060	**3.83**	**2.1793**
2	Gas	1625	**3.01**	**2.0043**
3	Gas	1732	**2.47**	0.0250
4	Gas	1732	**2.30**	**1.7293**
5	Gas	995	**2.29**	**2.0543**
6	Gas	922	2.27	0.3250
7	Gas	1146	2.04	0.4667
8	Gas	787	1.33	0.0167
9	Gas	520	1.2	**2.0710**
10	Coal	526	0.59	0.0083
11	Gas	234	0.5	0.0167
12	Gas	150	0.46	0.0083

Error! Not a valid bookmark self-reference. shows a geographical plot of the identified critical plants and the fault location. However, further investigation has concluded that the top critical plants do not vary much as fault location changes.

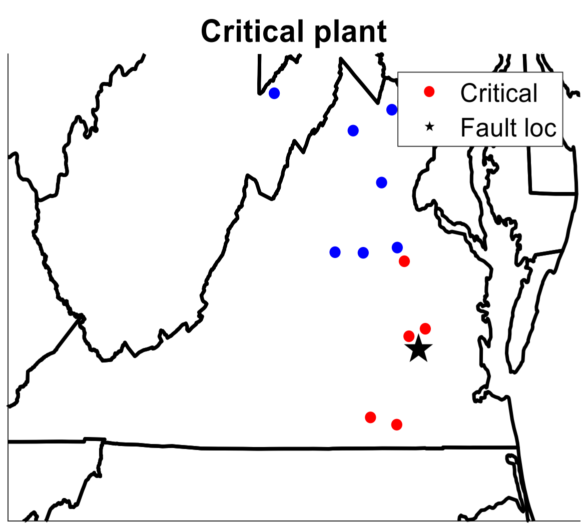


Figure 3-26. Critical plant identification

3.2.5   Recommended further study and analysis

Assessment of nuclear and large hydro plant contribution to grid strength

To achieve the goal of carbon-free grid by 2035, fossil-fueled generation are expected to gradually retire over the next 10 to 15 years. Although nuclear and hydro generation are carbon-free, a lot of the U.S. nuclear units are struggling in the power markets because of lowering natural gas prices and unfavorable capacity market structures. Some of the units are scheduled to retire in a few years if no actions are taken by legislatures to subsidize those units for their grid supporting properties in inertia and grid strength, as shown in **Figure 3-27**. Though the contribution of nuclear and hydro plants to system inertia are well documented, their roles in maintaining adequate grid strength by providing short circuit currents are less known and needs to be addressed. The objective of this study is to quantify the impacts of these plants in their own regions on grid strength, identify top contributors and provide recommendations for the decision-making of preserving or delaying retirements of these plants.

This assessment should implement grid strength related studies using the 2025 EI Summer Base Case, which incorporates generation additions and planned retirements by year 2025. The study scope should include all the existing nuclear plants and large hydro units (larger than 50MW) in EI, as shown in **Figure 3-28**. The contribution of each plant to grid strength should be quantified from different perspective in this task. First, as commonly used metrics for quantifying grid strength, short circuit level-based metrics should be applied to evaluate the impact of each considered plant. Then, the contribution of these plants to grid strength are evaluated by their impacts on weak grid related issues. The importance of these plants should be quantified based on their impacts on local voltage stability margin of critical transfer paths and on dynamic voltage responses after fault events.

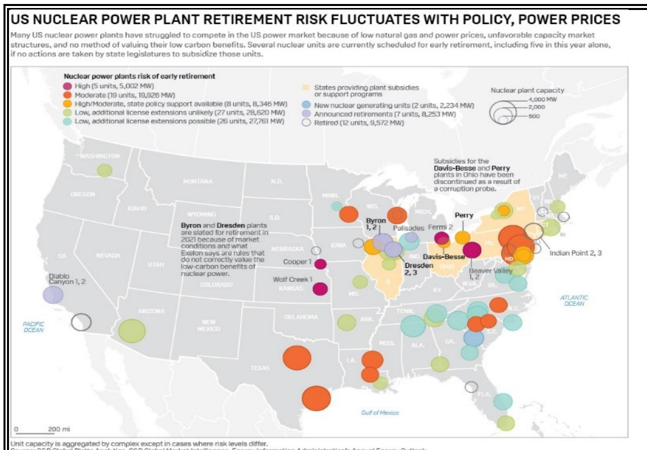


Figure 3-27. Nuclear plant retirement risk

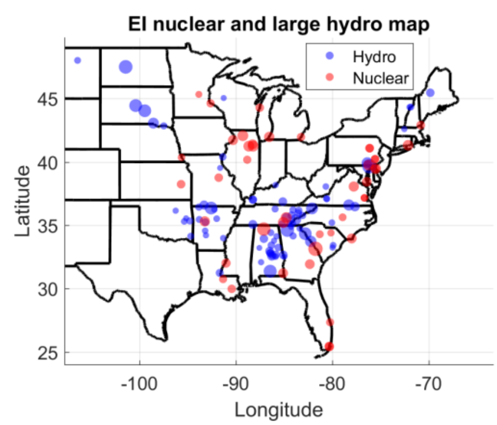


Figure 3-28. EI nuclear and large hydro map

Development of ERCOT 2025 synthetic model for gas/electricity dependency analysis

The objective is to develop a projected scenario of ERCOT of year 2025 by integrating future renewable additions and planned retirements. As a solution to model confidentiality issues, the team proposed the alternative to use the synthetic full-scale model developed by DOE support for ERCOT study, as shown in **Figure 3-29**. This model could be easily shared for gas/electric dependency analysis and in public for collaborative work within research community.

This task should integrate future renewables and retirements and develop a most updated 2025 electric base case based on the ERCOT synthetic model. New generation additions and retirements by 2025 from public data sources should be collected first. Then, power flow and dynamic models of a typical spring light load day and a winter peak day should be developed Generic models and parameters will be selected for new generation additions as a starting point.

The model should be used for gas and electric combined extreme weather analysis and also for evaluating grid strength and frequency support and identifying potential issues that arise with increasing penetration of renewables and retirements of synchronous units.

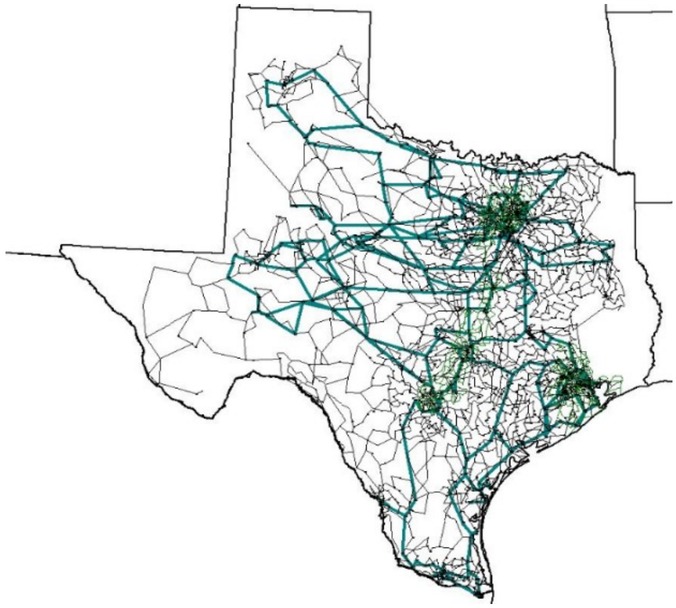


Figure 3-29. Topology of ERCOT synthetic model

3.3 National Base Case West

3.3.1 Overview

For WI electric base case, the main focus is to develop credible chronological base cases of the 2030 WI power grid considering planning data and generator retirement plan. To achieve this goal, National Renewable Energy Laboratory (NREL) leveraged the historical WI operating dataset, energy management system (EMS) model [43], and 2030 WECC planning data [44] [45] and created a mapping between production cost model (PCM) and EMS model.

Both heavy summer (HS) and heavy winter (HW) scenarios are generated and validated, each scenario has hourly AC power flow snapshots for one day (i.e., 24 snapshots for each scenario). The WI electric base cases serve as the foundation for reliability and resiliency metric evaluation, dynamic simulations, contingency analysis, and extreme event impact modeling.

3.3.2 Assumptions

To develop WI electric base cases, the existing WI model and data are the baselines, and additional data from credible sources is processed and incorporated into the base case development process. A number of assumptions are adopted by the NREL team when building the WI electric base cases. These assumptions can be categorized into the following clusters.

- Data sources.
- Handling Discrepancy.
- Model Validation Criteria.

3.3.2.1 Data Sources

The data sources for WI electric base case development mainly include two parts, namely the historical WI EMS data and the WECC planning data. For historical WI data, the NREL team leveraged the WECC system HS and HW data in 2020 as the baseline. According to existing WECC EMS data, the 2020 WECC generation capacity mix by fuel is shown in **Figure 3-30**. As shown in **Figure 3-30**, natural gas, hydro, and coal are the three major fuel sources in WECC 2020 base case. Wind and solar take 9% and 7.7% of the total generation capacity, respectively. **Table 3-18** summarizes the 2020 WECC data in HS scenario.

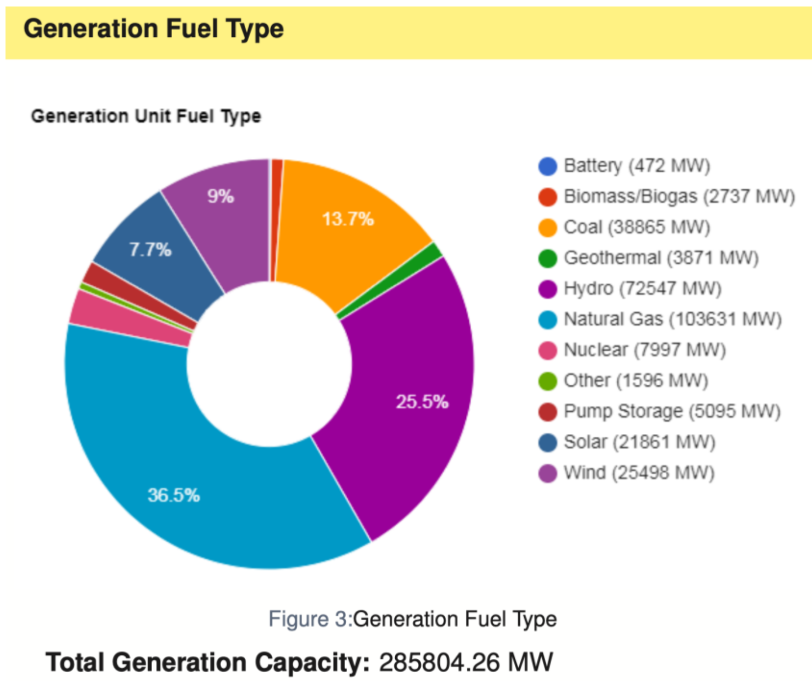


Figure 3-30. WECC generation mix based on EMS data

Table 3-18. Overview of Generation Capacity in WECC 2020 HS Base Case

Generation Type	# Units	Total MW	% MW Capacity
Solar	414	18,180	7%
Wind	424	27,995	10%
Hydro	1,329	73,456	27%
Energy Storage	34	1,911	1%
Other	22	861	0%
Geothermal	66	2,064	1%
Synchronous Fossil (Coal + Natural Gas + Nuclear)	1,932	148,123	54%
Total	4221	272,590	100%

WECC published the 2030 resource adequacy assessment report [44] in Dec. 2020, and 2030 PCM data [45] in Jun. 2021. These two reports provide the most up-to-date reference regarding the WI electric grid in 2030. Therefore, the NREL team leveraged these data to generate WI electric base cases for 2030.

In the WECC planning model, WI electric grid is divided into five subregions, namely Northwest Power Pool Northwest (NWPP-NW), NWPP Northeast (NWPP-NE), NWPP Central (NWPP-C), California-Mexico (CAMX), and Desert Southwest (DSW), as demonstrated in **Figure 3-31**. The WECC 2020 base case generation capacity and the projected 2030 generation capacity are compared in **Table 3-19**. As shown in **Table 3-19**, little change in thermal and hydro generation capacity is projected. The retired Coal-fire unit capacity is largely offset by the addition of Natural Gas unit capacity. The most significant changes in the generation capacity mix include the rapid growth in solar generation capacity and Distributed Energy Resource (DER) capacity.

Figure 3-31. WECC Planning Subregions

Table 3-19. WECC 2030 Generation Capacity Forecast (Unit: GW)

Generation Type	2020 Base	2030 Forecast
Utility-Scale Solar	18	38
Wind Onshore	28	36
Hydro (55 GW reportable to NERC)	73	68 (~55 Dispatchable)
Energy Storage (Pump & Battery)	1.9	10 (3.8 Pump Storage)
Distributed Energy Resources (DER)	8	28
Demand Response (DR)	NA	4.4
Thermal (Coal + Natural Gas + Nuclear)	148	142
Gen Capacity Total (excluding DR and DER)	269	**294**

In terms of projecting load growth and peak load profile for WI 2030, the existing WI 2020 baseline data are employed as a reference, and the following assumptions are implemented when generating WI 2030 base cases:

- The winter peak is expected from mid-January to February.
- Summer peak is expected from mid-July to late-August in general.
- There are extreme peak load projections with 5% probability.

- <1% annual net WI system load increase from 2020 to 2030.

Figure 3-32 demonstrates the expected peak load capacity for WI 2030 base case and the projected extreme peak load with 5% probability. In **Figure 3-32**, blue bars indicate the expected peak load, and the red bars indicate the extreme load peak. Take the CAMX subregion for example, the 23% above the red bar indicates that the extreme load peak in CAMX subregion is 23% higher than the expected peak load. To generate heavy load peak cases for WI 2030, an additional step is to identify the time of the year when the total WI load reaches the peak. The extreme peak loads of these subregions do not appear in the same period based on previous WI operating records, as listed in **Table 3-20**. According to **Table 3-20**, peak load in NWPP-NW and NWPP-NE appears in the winter months because of the high heating demand. For other subregions DSW, NWPP-C, and CAMX, the peak load appears in summer. For the entire WI electric grid, the extreme peak load is primarily determined by the peak load of CAMX, as shown in **Figure 3-32**. Therefore, the peak load and the extreme peak load for WI 2030 base case are expected to occur in late August when CAMX reaches its peak load.

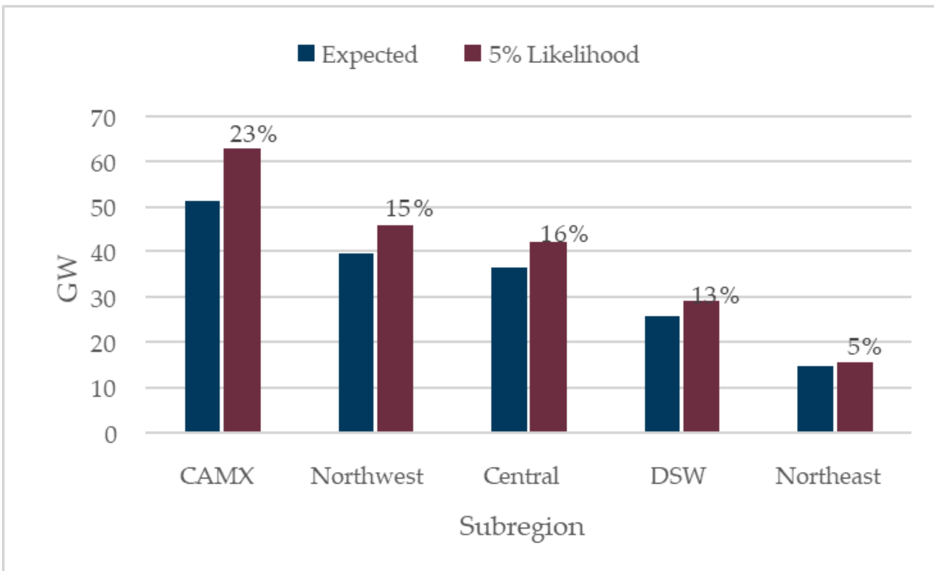


Figure 3-32. WI 2030 Base Case Peak Load by Subregion

Table 3-20. Projected Peak Load in WI 2030 HS

	Peak Time	Peak Demand
NWPP-NW	Mid-January	39.7 GW
NWPP-NE	Early February	14.8 GW
DSW	Early July	25.7 GW
NWPP-C	Mid-July	36.4 GW
CAISO/CAMX	Late August	51.3/60.3 GW
Subtotal		**167/176 GW**

Aside from the growth in generation capacity and load, the expansion of the transmission grid, including transmission lines and substation capacities, is another important factor to accommodate the investment of new generation plants and the generation increase from existing generators. However, the detailed transmission grid expansion plan and data are not accessible to the project team. Therefore, it is assumed that the existing transmission grid infrastructure in the existing WI 2020 baseline case remained unchanged in the developed WI 2030 base case.

3.3.2.2 Handling Discrepancy

The model discrepancy can be identified when comparing different data sources. One major aspect of the model discrepancy comes from the retirement of generators. As listed in **Table 3-21**, a number of generators with confirmed retirement dates from 2020 to 2030 can still be found in the WECC 2030 HS planning case. Their generation outputs are summarized in **Table 3-21**, with a total generation of 6.2 GW. When building the WI 2030 base cases, the project team disabled these generators with confirmed retirement dates and adjusted the generation output of other generators accordingly to ensure a feasible AC power flow can be achieved.

Table 3-21. Outputs from Generators with Confirmed Retirement in WECC 2030 Planning Case

Subregion	Unit Name	Unit #	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date	Output in 2030 planning case (MW)
NWPP-C	Cabin Creek	2	150	Water	12/1/66	3/31/20	87.46
NWPP-C	Cherokee	4	380.8	Natural Gas	8/13/17	12/31/27	258.921
NWPP-C	Clark	4	72.4	Natural Gas	6/1/73	12/31/20	0.02
NWPP-NE	Colstrip	3	740	Coal	1/1/84	12/31/27	715.76
DSW	COP	1	87	Natural Gas	7/1/80	12/31/30	46.574
NWPP-NW	Copco 1	1	10	Water	1/1/18	12/31/20	9.32
NWPP-NW	Copco 1	2	10	Water	11/1/22	12/31/20	9.5
NWPP-NE	Craig	3	446.38	Coal	10/1/84	12/31/30	278.956
NWPP-C	Dave Johnston	1	113.64	Coal	2/1/59	12/31/27	84.05
NWPP-C	Dave Johnston	2	113.64	Coal	1/1/61	12/31/27	95.09
NWPP-C	Dave Johnston	3	229.5	Coal	12/1/64	12/31/27	157.09
NWPP-C	Dave Johnston	4	360	Coal	7/1/72	12/31/27	217.98
NWPP-NW	Fall Creek	1	0.5	Water	9/1/03	12/31/20	0.16
NWPP-C	Fort Churchill	2	115	Natural Gas	9/1/71	12/31/21	83.16
NWPP-NE	Genesee	2	400	Coal	1/1/89	4/2/28	420.09
NWPP-NE	Genesee	1	400	Coal	1/1/94	4/2/28	424.87
NWPP-NE	Genesee	3	466	Coal	11/1/04	4/2/29	503.25
NWPP-C	Hayden	1	190	Coal	7/1/65	12/31/30	173.99
CAMX	Haynes	1	230	Natural Gas	9/1/62	12/31/29	95.03
NWPP-NW	Iron Gate	1	18	Water	2/1/62	12/31/20	8.05
NWPP-NW	John C Boyle	2	47.63	Water	10/1/58	12/31/20	13.03
NWPP-C	Las Vegas Cogen	1	49.79	Natural Gas	6/1/94	12/31/29	43.69
NWPP-C	Las Vegas Cogen	2	11.5	Natural Gas	6/1/94	12/31/29	2.61
NWPP-C	Naughton	1	163.19	Coal	5/1/63	12/31/29	156.25
NWPP-C	Naughton	2	217.59	Coal	10/1/68	12/31/29	206.19
NWPP-C	North Valmy	1	138.6	Coal	12/1/81	12/31/21	227.78
DSW	NWM	1	81	Natural Gas	5/1/60	12/31/22	56.14

Subregion	Unit Name	Unit #	Nameplate Capacity	Primary Fuel Type	Commission Date	Retirement Date	Output in 2030 planning case (MW)
DSW	NWM	2	81	Natural Gas	6/1/63	12/31/22	63.16
DSW	San Juan	1	369	Coal	12/1/76	6/30/22	311.83
DSW	San Juan	4	555	Coal	4/1/82	6/30/22	482.8
DSW	Springerville	1	424.8	Coal	6/1/85	12/31/27	366.959
NWPP-NE	Sundance	6	401	Coal	10/1/01	4/2/21	191.81
NWPP-NE	Sundance	4	406	Coal	9/1/07	4/2/21	215.88
NWPP-NE	Sundance	3	368	Coal	1/1/76	4/2/22	198.56
NWPP-NW	West Side	1	0.6	Water	3/22/05	12/31/20	1

Another discrepancy worth mentioning is the missing data on new generating resources in the WECC 2030 planning case. For example, there are 12 nuclear generating units expected to be commissioned on 01/01/2027 at Antelope (PACE) as per the WECC PCM model. The total capacity is 0.6 GW, and these units are not included in the WECC 2030 planning case. Because the capacities of these new generating units are relatively small compared to the peak WI demand, they are not included in the WI 2030 electric base case buildout as well.

3.3.2.3 Model Validation Criteria

To validate the development of WI 2030 electric base cases, the guidelines of NERC are employed to ensure the validation criteria are consistent with NERC requirements [46]. In terms of steady-state model validation standard, the acceptable differences listed in **Table 3-22** are adopted in this project.

Table 3-22. Guidelines and Standards of NERC and WECC MOD-033

Quantity	Acceptable Differences
Bus voltage magnitude	±2% (≥500 kV) ±3% (230≥kV≥345 kV) ±4% (100>kV>230 kV)
Generating Bus voltage magnitude	±2%
Real power flow	±10% or ±100 MW
Reactive power flow	±20% or ±200 MVar
Difference in % normal loading	±10% based on branch normal continuous rating

3.3.3 Approach

3.3.3.1 Workflow

The WECC 2030 PCM model and planning case only contains the peak load power flow snapshot. To build chronological cases for WI 2030 electric grid, additional mapping between the WECC planning case and the historical EMS case is required to map generation and load to each bus and integrate the load and generation shape. Overall, the workflow of this process is described in **Figure 3-33**.

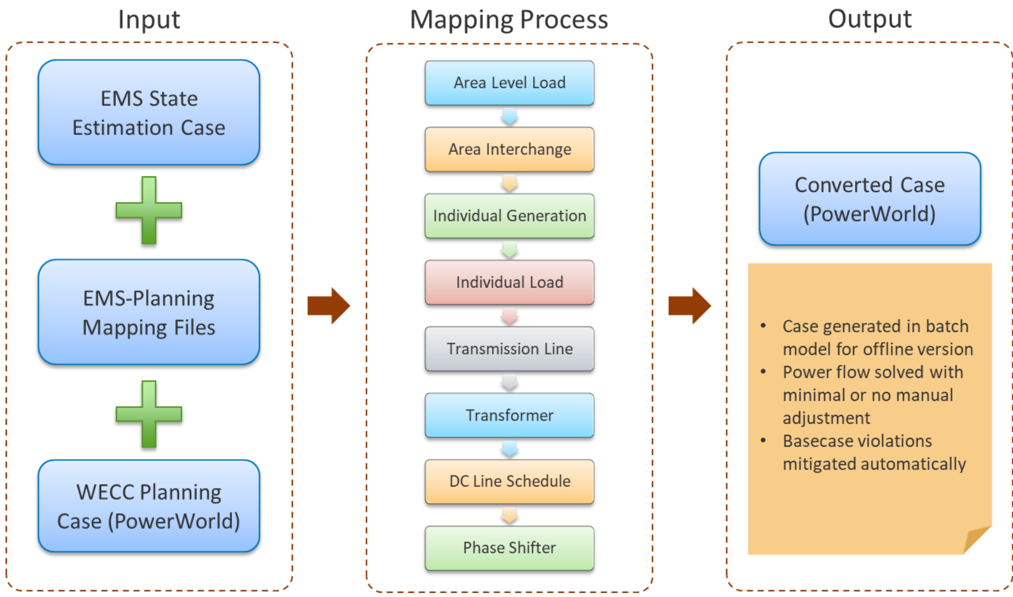


Figure 3-33. The flowchart of WI Base Case Conversion

Due to a significant increase in solar generation capacity, model discrepancy, and lack of transmission grid planning data, it is possible that the AC power flow of the generated WI 2030 case does not converge. To resolve this issue, the following steps are adopted to generate chronological base cases:

1. Prepare the WECC planning base case by updating interface definition, reviewing direct current (DC) line directions, updating load Automatic Gain Control flags, and voltage regulating buses for specific units as needed.
2. Solve EMS State Estimation (SE) case to ensure power flow can be solved properly. Extract data from the historical EMS State Estimation (SE) case as reference.
3. Use WECC 2030 PCM load data as a reference to scale regional load and generator outputs.
4. Adjust renewable generation outputs to meet WECC 2030 generation capacity mix.
5. Calculate AC power flow and collect warnings and errors. Manually scale-up generation capacity to resolve errors. Ensure the AC power flow converges.
6. Review the AC power flow results and shortlist voltage violations and branch violations. Voltages should be within 0.85 – 1.15 p.u. and 0.9 – 1.1 p.u. for buses with 230kV and above. For branch flows, if branch flow violation is larger than 125%, manual adjustment is needed.

3.3.3.2 Generating WECC 2030 HS planning case

The WI 2030 electric base cases contain HS base cases and HW base cases. Actual WECC system peak demands recorded in EMS between 2010 and 2020 are employed as references. However, the EMS records only illustrate information regarding the peak demand. To simulate HS and HW, where the peak demand might become much higher than the expected forecasts, the NREL team employed Quartile 3 values when generating system loads for WI 2030 HS and HW base cases, while the median values are used for renewable energy generations. **Figure 3-34** explains how to understand the median value and Quartile value [47].

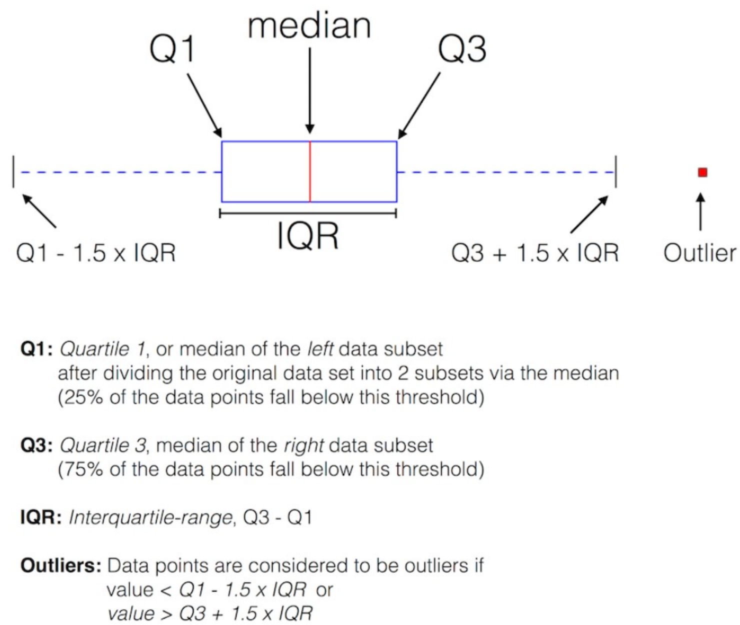


Figure 3-34. Interpretation of WECC PCM Data Boxplots

From the WECC PCM data files, the 2030 WECC HS demand was simulated with the highest demand of 176 GW. The projected WI 2030 summer load profile is shown in **Figure 3-35**, and the boxplot is shown in **Figure 3-36**. As discussed in **Figure 3-34**, the Quartile 3 load value is used to represent the WI 2030 HS demand.

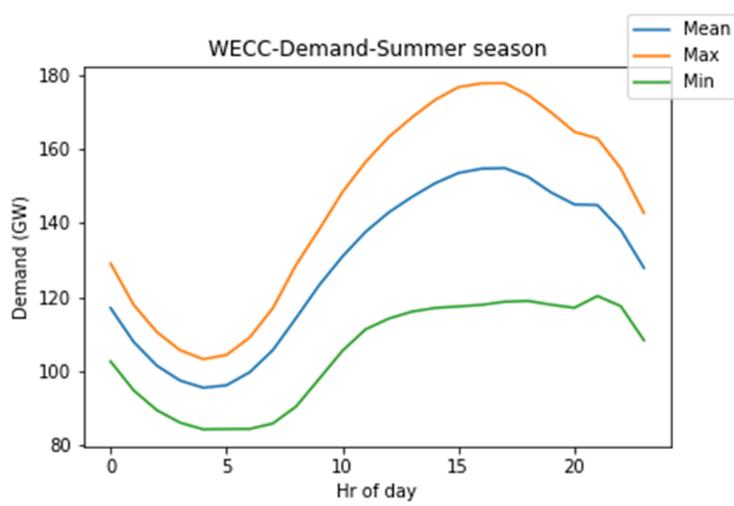


Figure 3-35. WI 2030 Summer Daily Demand Projection

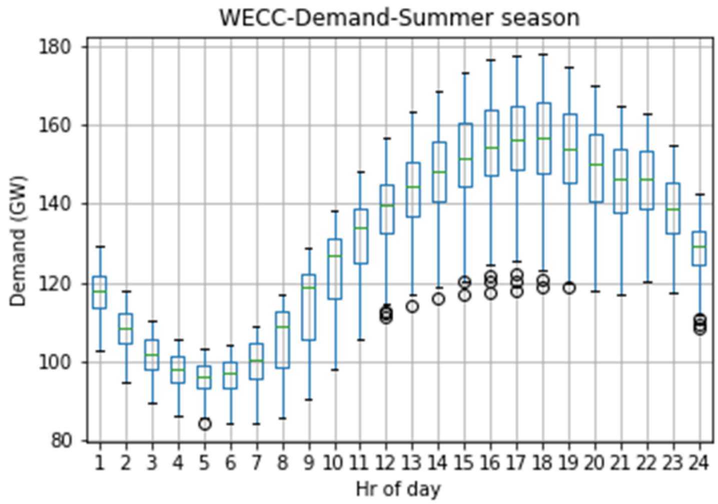


Figure 3-36. Boxplot of the WI 2030 Summer Daily Demand Profile

The above plots in **Figure 3-35** and **Figure 3-36** are created by collecting hourly data from the 2030 WECC PCM output data over the summer (i.e., Jun 15 – Sep 15, a total of 93 days). Namely, the project team leveraged a pool of 93 data points for each hour. **Figure 3-35** shows the maximum, mean, and minimum of this pool for each hour, while **Figure 3-36** depicts its other statistical attributes (refer to **Figure 3-34**) for each hour.

Figure 3-35 and **Figure 3-36** show that the variability range of hourly demand as the percentage of the mean is not very significant, especially when compared with intermittent generation output from renewable sources such as wind (more details will be given in the next subsection). It confirms that to improve near-term resilience, the key focus should be on efficient and effective redispatch strategy-building and adequate ramping reserves to handle the uncertainty in generation resources.

3.3.3.3 WI 2030 HS Data: An Example

The dataset used to create WI 2030 HS case is described in detail in this subsection as an example. Since the WI 2030 HS load profile has been discussed in the previous subsection, here the focus is on the generation output data of different types of generators.

- **Hydro Generation**

From the WECC PCM data files, the total Hydro MW output was simulated between 13 GW and 44 GW for the 2030 summer. The projected hydro generation output and the corresponding boxplot are provided in **Figure 3-37** and **Figure 3-38**, respectively. Note that the 44 GW output of 55 GW dispatchable hydro capacity need to be verified on draught conditions when extreme weather impact should be incorporated.

Figure 3-37 and **Figure 3-38** indicate that the WECC-wide hydro generation can vary over the ±10 GW band around the mean almost uniformly for every hour, depending on natural resource availability.

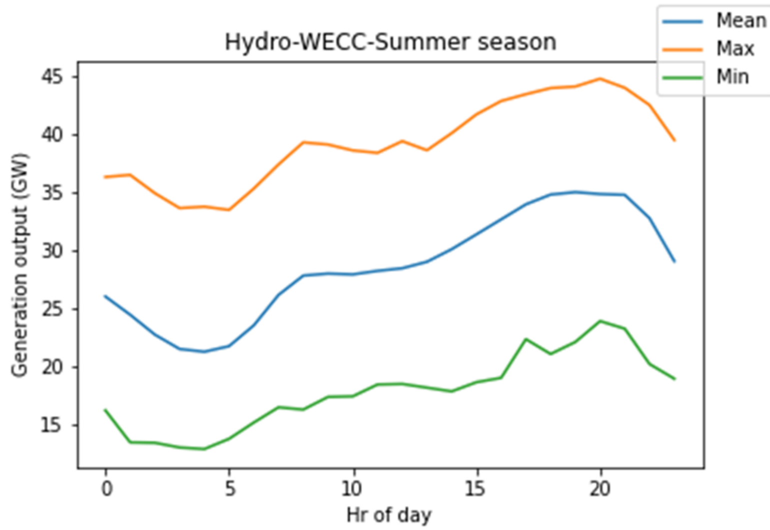


Figure 3-37. Projected Hydro Generation Output for WI 2030 HS Case

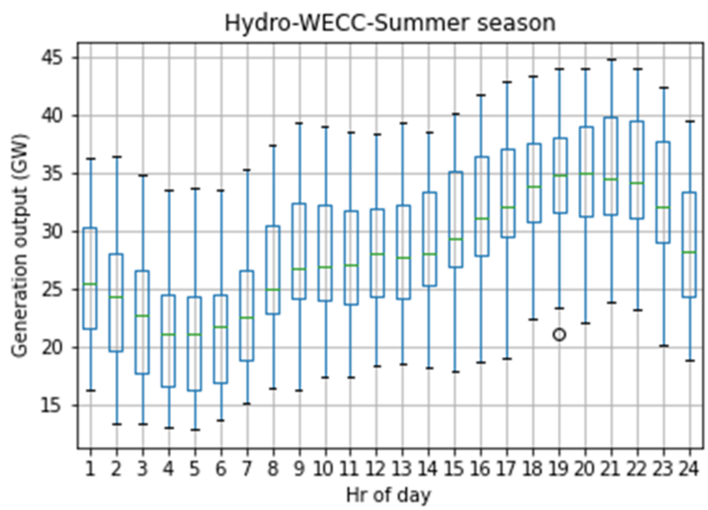


Figure 3-38. Boxplot of Projected Hydro Generation Output for WI 2030 HS Case

- **Solar Generation**

From the WECC PCM data files, the total Solar MW Peak output was simulated between 28 GW and 38 GW during peak sunshine hours. The projected solar generation output and the corresponding boxplot are provided in **Figure 3-39** and **Figure 3-40**, respectively. However, the 38 GW output of the projected capacity of 38 GW may overestimate the actual solar generation output. **Figure 3-39** and **Figure 3-40** indicate that the WECC-wide generation has a narrower confidence interval compared to the other generation types and the hourly medians and means are both closer to the maximum values. In **Figure 3-40**, the majority of the non-zero minimum values are outliers, meaning that those reduced solar generation scenarios are rare and may be the results of specific weather conditions.

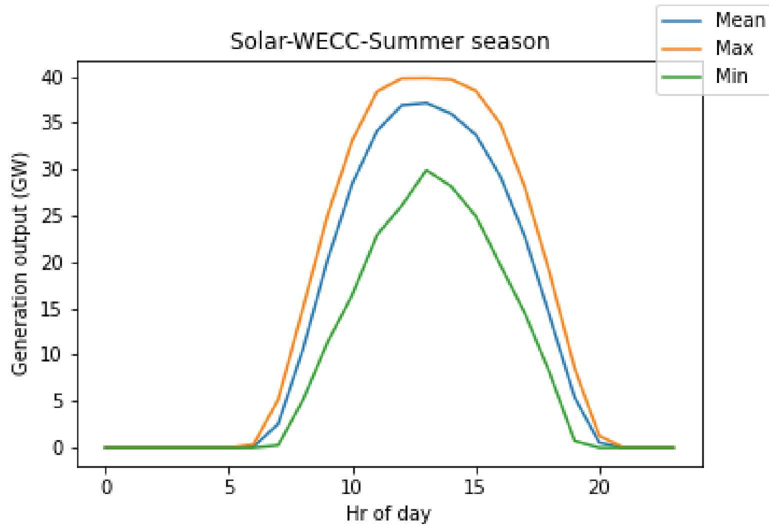


Figure 3-39. Projected Solar Generation Output for WI 2030 HS Case

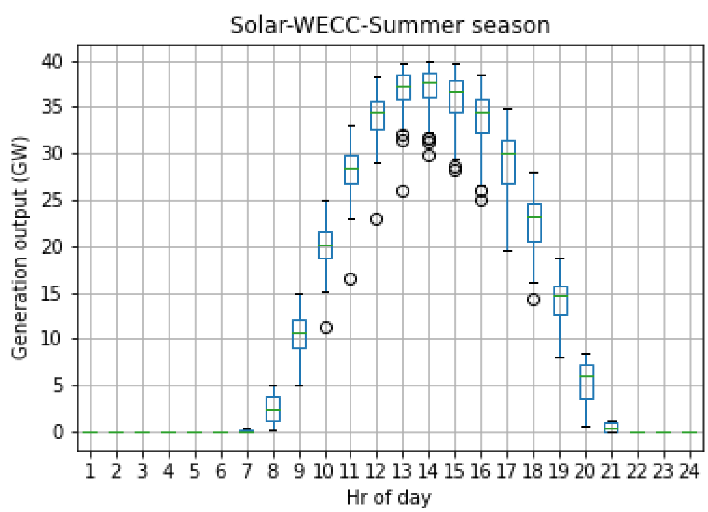


Figure 3-40. Boxplot of Projected Solar Generation Output for WI 2030 HS Case

- **Wind Generation**

From the WECC PCM data files, the total Wind MW Peak output was simulated between 2 GW and 24 GW throughout the 2030 summer. The projected wind generation output and the corresponding boxplot are provided in **Figure 3-41** and **Figure 3-42**, respectively. Note that wind generation output typically cannot reach its peak during hot summer days, and high fluctuations can be expected as shown in **Figure 3-41** and **Figure 3-42**. Moreover, **Figure 3-41** and **Figure 3-42** indicate that the WECC-wide wind generation possibly has the largest range of variability as the percentage of the mean, among the generation-resource studies included here. The degree of uncertainty prevails nearly uniformly over each hour of the day.

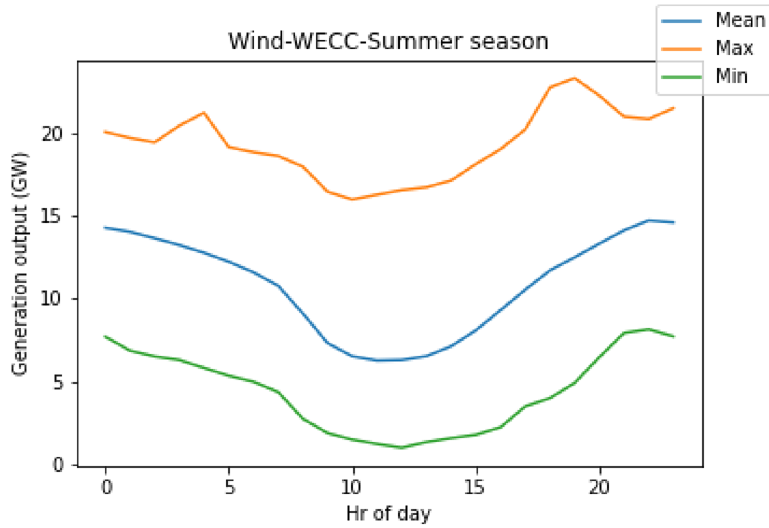


Figure 3-41. Projected Wind Generation Output for WI 2030 HS Case

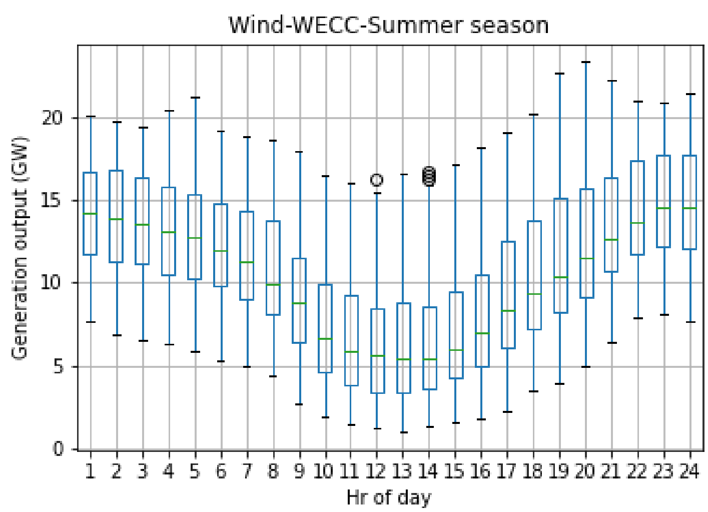


Figure 3-42. Boxplot of Projected Wind Generation Output for WI 2030 HS Case

- **Natural Gas Generation**

From the WECC PCM data files, the total Natural Gas MW Peak output was simulated between 15 GW and 88 GW for 2030 summer days. The projected natural gas generation output and the corresponding boxplot are provided in **Figure 3-43** and **Figure 3-44**, respectively. High natural gas generation output occurs on hot summer days. **Figure 3-43** and **Figure 3-44** indicate that the WECC-wide natural gas generation is largely correlated with the other renewable resource output. For example, the natural gas generation output trend is low during the daytime while solar generation is high.

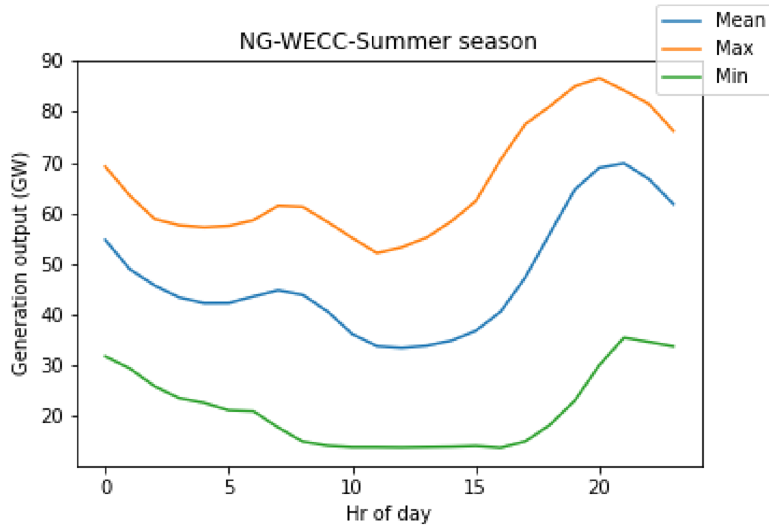


Figure 3-43. Projected Natural Gas Generation Output for WI 2030 HS Case

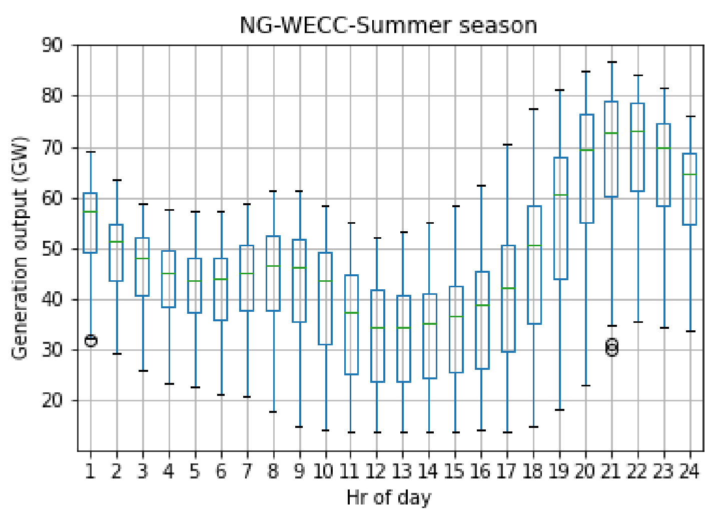


Figure 3-44. Boxplot of Projected Natural Gas Generation Output for WI 2030 HS Case

Figure 3-43 and **Figure 3-44** already demonstrated that the natural gas generation output is influenced by renewable generation output, especially solar generation. This phenomenon is more significant in CAMX region because of its high solar penetration. **Figure 3-45** and **Figure 3-46** are the projected natural gas generation and its boxplot for the CAMX region. As can be observed from **Figure 3-45** and **Figure 3-46**, the generation output increase dramatically from 17:00 to 20:00 on hot summer days, which is also known as the 'duck curve' [48].

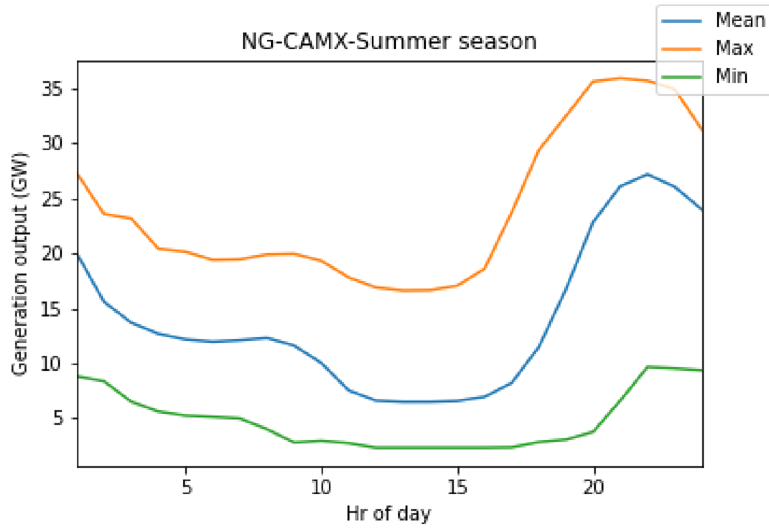


Figure 3-45. Projected CAMX Natural Gas Generation Output for WI 2030 HS Case

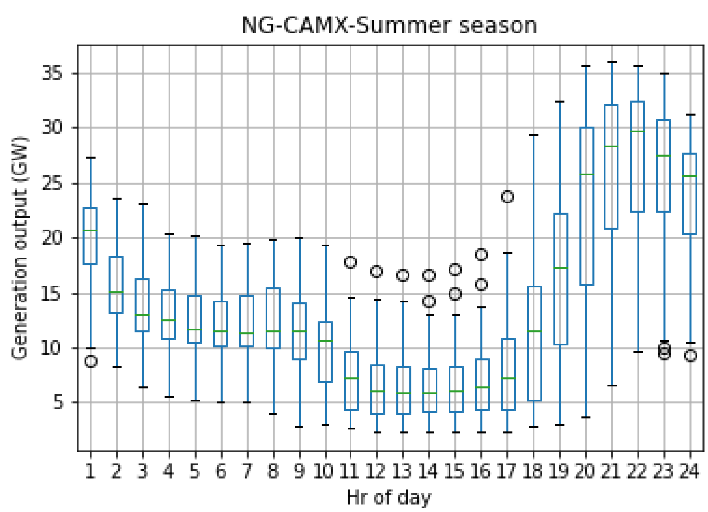


Figure 3-46. Boxplot of Projected CAMX Natural Gas Generation Output for WI 2030 HS Case

- **Nuclear Generation**

Generally, nuclear generation output in WECC has a very narrow range because of the nature of nuclear generation power plants. Based on historical nuclear generation output from 2015 to 2018, the nuclear generation output typically ranges from 5.5 GW to 7.5 GW, as shown in **Figure 3-47**. From the WECC PCM data files, the total nuclear MW output is reduced to 5.7 GW and 4.4 GW at high demand and low demand period, respectively. The decrease in peak nuclear power output is largely due to the retirement of nuclear power plants from 2020 to 2030. For example, Diablo Canyon Power Plant has two nuclear units, each with a capacity of 1.1 GW, that are expected to retire in 2024 and 2025, respectively. The projected nuclear generation output in WI 2030 HS base case is shown in **Figure 3-48.**

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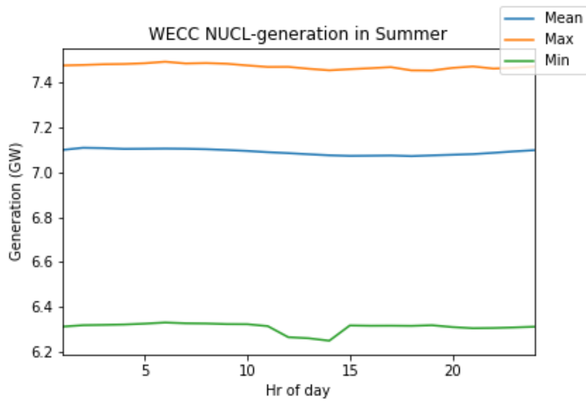
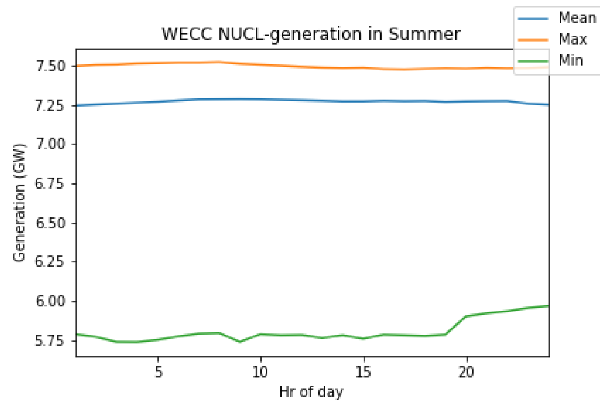
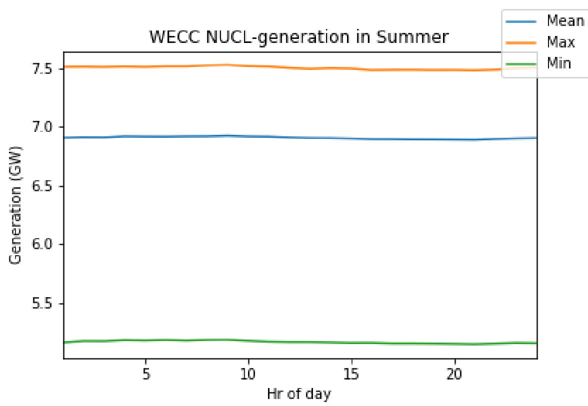


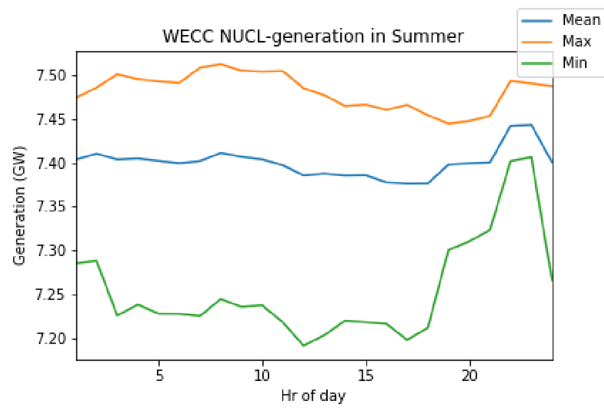
(a) Year 2015



(b) Year 2016



(c) Year 2017



(d) Year 2018

Figure 3-47. WECC Daily Nuclear Generation Output from 2015-2018

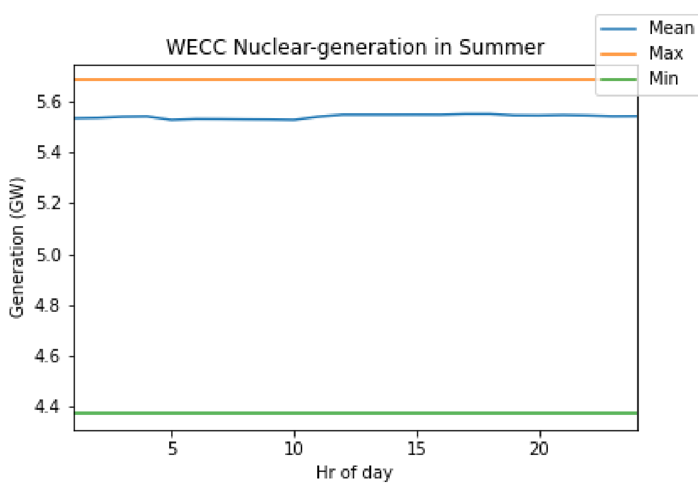


Figure 3-48. Projected Nuclear Generation Output for WI 2030 HS Case

3.3.4 WI 2030 Electric Base Case

Based on data and assumptions described in **Section 3.3.2** and the approaches described in **Section 3.3.3**, the WI 2030 electric base cases are generated. One case for HS and one case for HW are constructed to serve as the baseline for WI electric grid reliability and resilience assessment in extreme scenarios. For each base case, chronological AC power flow snapshots for 24 hours are available. The summaries of WI 2030 base cases are given below.

3.3.4.1 WI 2030 HS Case

Based on the assumed WI summer load growth projections and WECC 2030 PCM data, the HS daily load profile is shown in **Figure 3-49**. The load peak and valley are 167 GW and 99 GW, respectively. **Figure 3-50** illustrates the breakdown of WI 2030 HS load by region.

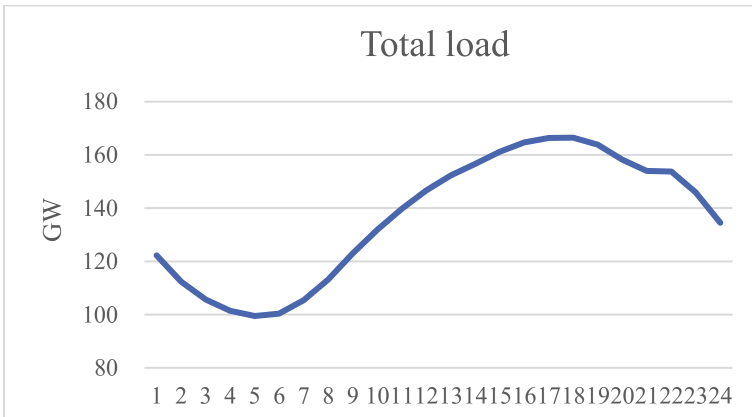


Figure 3-49. Daily WI electric load in 2030 HS

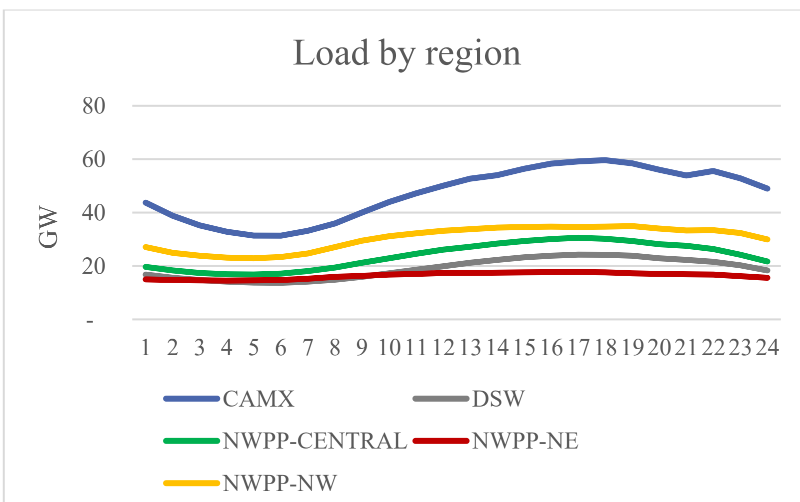


Figure 3-50. Daily WI electric load in 2030 HS by region

The generation output from different fuel types in the WI 2030 HS case is shown in **Figure 3-51**. The generation peak and valley are 171 GW and 102 GW, respectively. In terms of power loss, the lowest power loss rate is around 2.4% and occurs at low load period (e.g., early morning). The highest power loss rate is around 3.7% and occurs at late noon hours when solar generation reaches its peak.

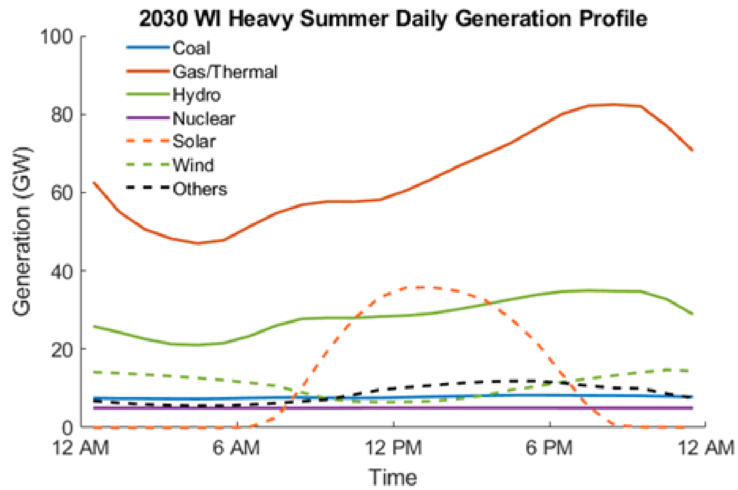


Figure 3-51. WI 2030 HS daily generation profile by type

Figure 3-52 illustrates the breakdown of solar generation in the WI 2030 heavy summer case by region. CAMX has the highest generation capacity and NWPP-NW has very little solar generation output (i.e., peak solar generation is less than 0.2 GW).

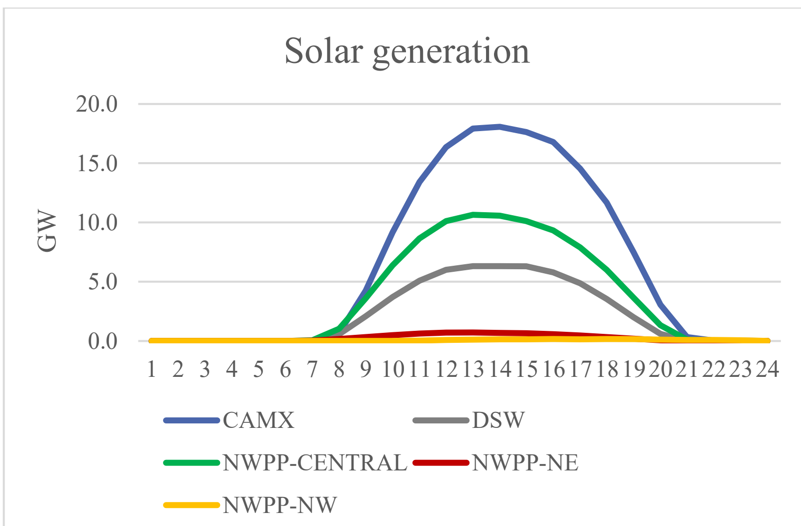


Figure 3-52. WI 2030 HS daily solar generation profile by region

Figure 3-53 illustrates the breakdown of wind generation in the WI 2030 HS case by region. Different from the solar generation profile, the wind power output is high throughout the night but drops considerably during the day. Typically, the wind generation profile and solar generation profile are complementary.

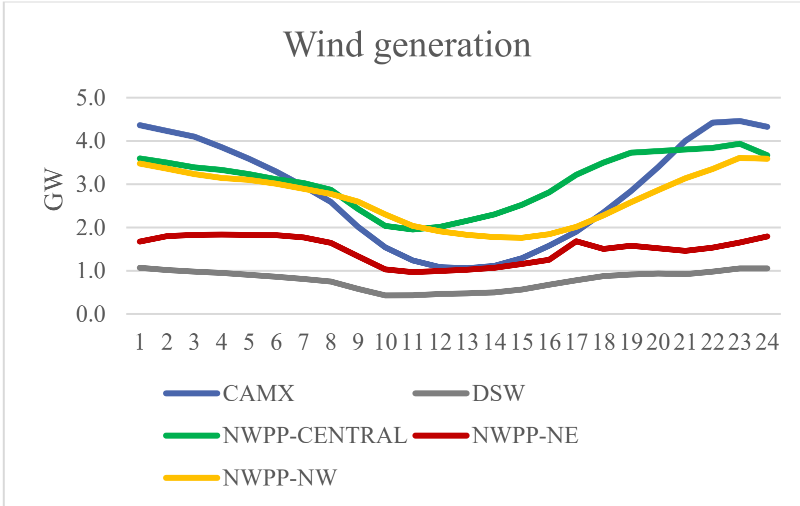


Figure 3-53. WI 2030 HS daily wind generation profile by region

Figure 3-54 illustrates the breakdown of nuclear generation in the WI 2030 HS case by region. Because of the retirement of Diablo Canyon nuclear power plants, only two regions, DSW and NWPP-NW, have nuclear power plants operating in WI 2030 base case.

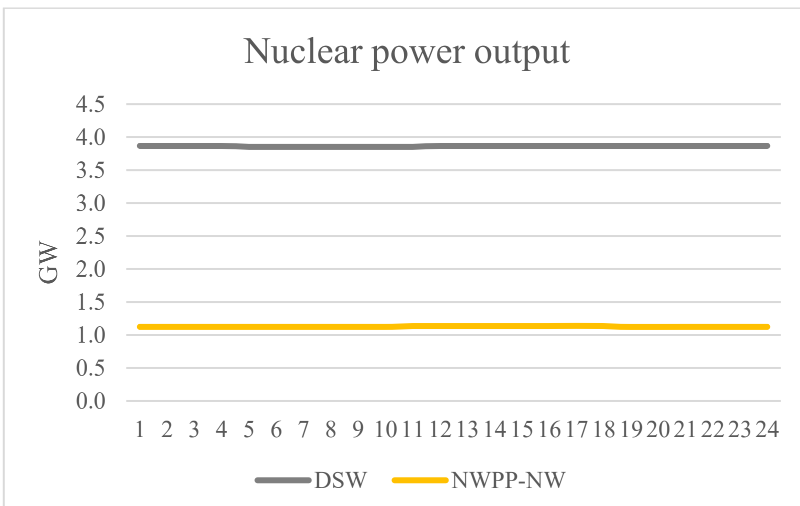


Figure 3-54. WI 2030 HS daily nuclear generation profile by region

Figure 3-55 illustrates the breakdown of coal generation in the WI 2030 HS case by region. CAMX and NWPP-NW regions have almost zero coal generation output in 2030.

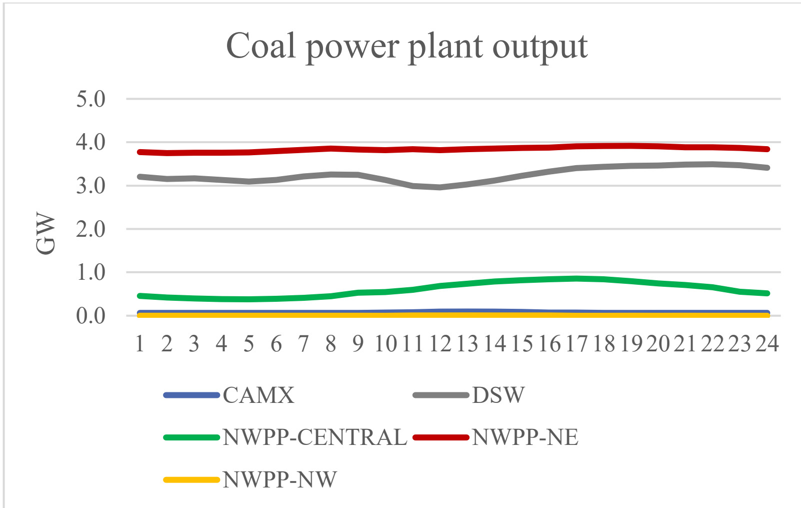


Figure 3-55. WI 2030 HS daily coal generation profile by region

Figure 3-56 illustrates the breakdown of gas and other thermal generation in the WI 2030 HS case by region. The gas and other thermal generation profile follow the WI load profile.

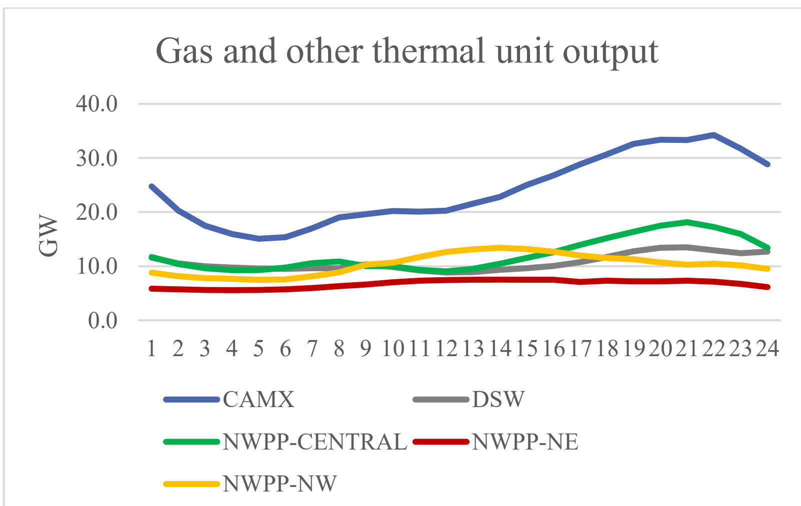


Figure 3-56. WI 2030 HS daily gas and other thermal generation profile by region

Figure 3-57 illustrates the breakdown of hydro generation in the WI 2030 HS case by region. The majority of hydro generation comes from the NWPP-NW region.

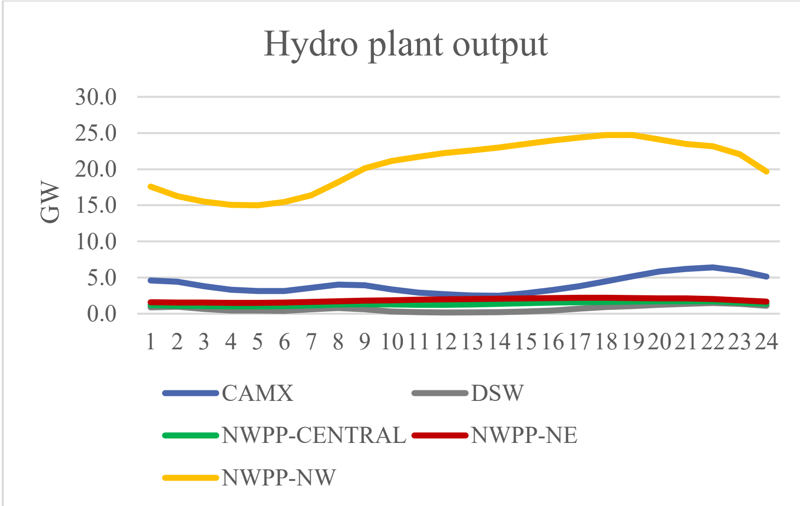


Figure 3-57. WI 2030 HS daily hydro generation profile by region

3.3.4.2 WI 2030 HW Case

Based on the assumed WI winter load growth projections and WECC 2030 PCM data, the HW daily load profile is shown **Figure 3-58**. The load peak and valley are 133 GW and 98 GW, respectively. **Figure 3-59** illustrates the breakdown of WI 2030 HW load by region.

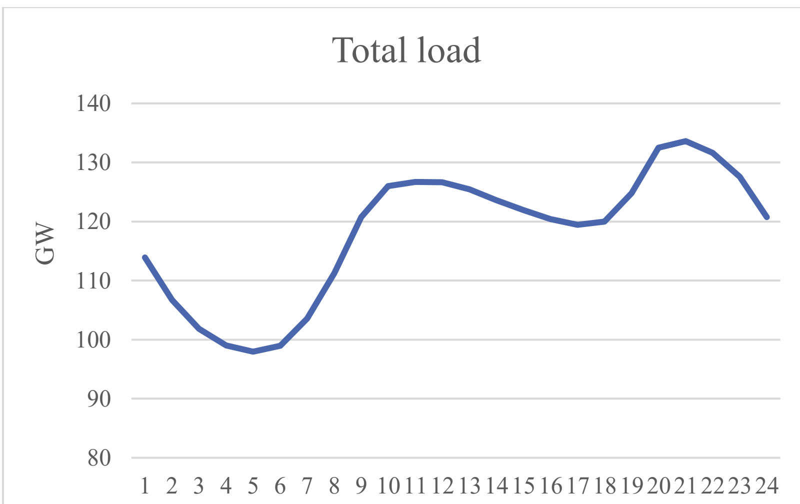


Figure 3-58. Daily WI electric load in 2030 HW

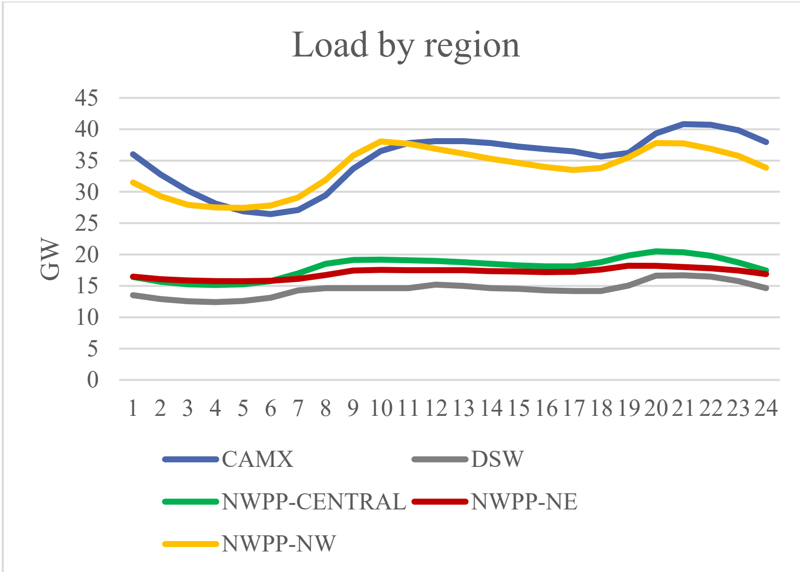


Figure 3-59. Daily WI electric load in 2030 HW by region

The generation output from different fuel types in the WI 2030 HW case is shown in **Figure 3-60**. The generation peak and valley are 139 GW and 102 GW, respectively. In terms of power loss, the loss rate in HW is generally higher than that in HS, probably due to the reduction in the solar generation which leads to heavier power transmission from generators to load centers. The lowest power loss rate is around 3.6% and the highest power loss rate is around 4.3%.

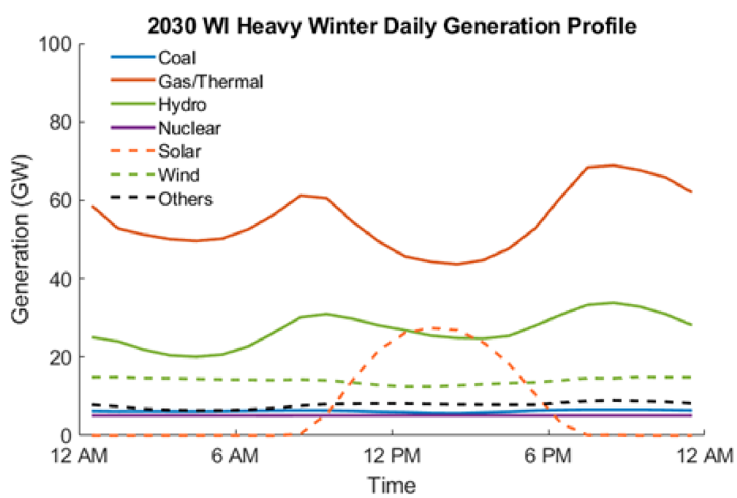


Figure 3-60. WI 2030 HW daily generation profile by type

Figure 3-61 illustrates the breakdown of solar generation in the WI 2030 HW case by region. CAMX has the highest generation output, but the peak output drops from 18 GW in HS to 13.7 GW in HW.

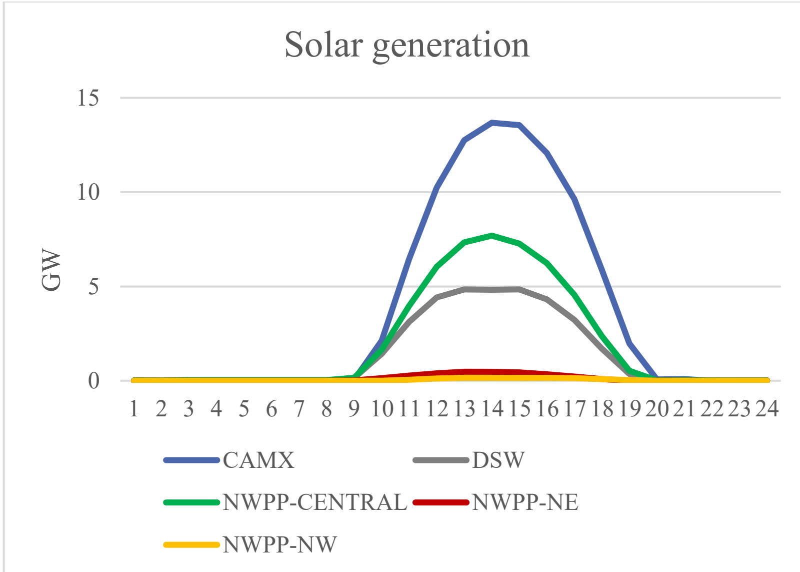


Figure 3-61. WI 2030 HW daily solar generation profile by region

Figure 3-62 illustrates the breakdown of wind generation in the WI 2030 HW case by region. Unlike the pattern observed in WI 2030 HS case that wind and solar generation are complementary. In WI 2030 HW case, the variation of wind generation is not significant, possibly due to the high wind in winter times.

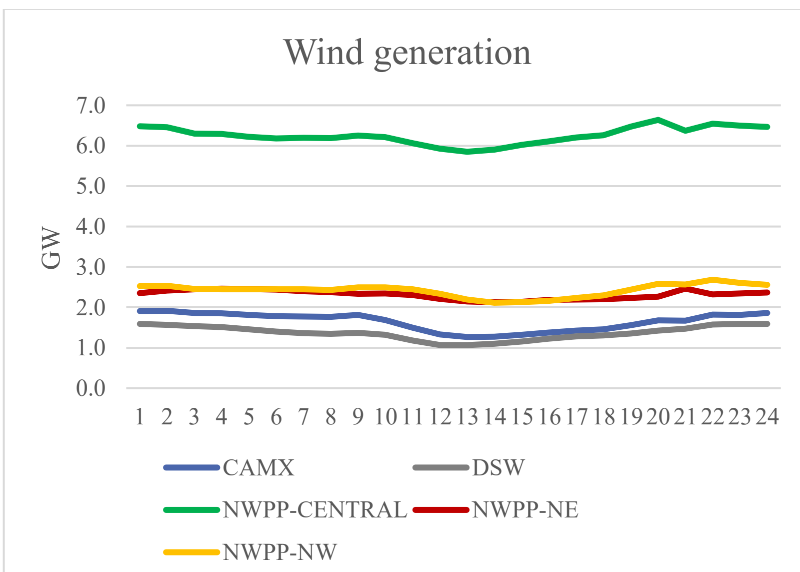


Figure 3-62. WI 2030 HW daily wind generation profile by region

Figure 3-63 illustrates the breakdown of nuclear generation in the WI 2030 HW case by region. The nuclear power output profiles in WI 2030 HS and WI 2030 HW are identical.

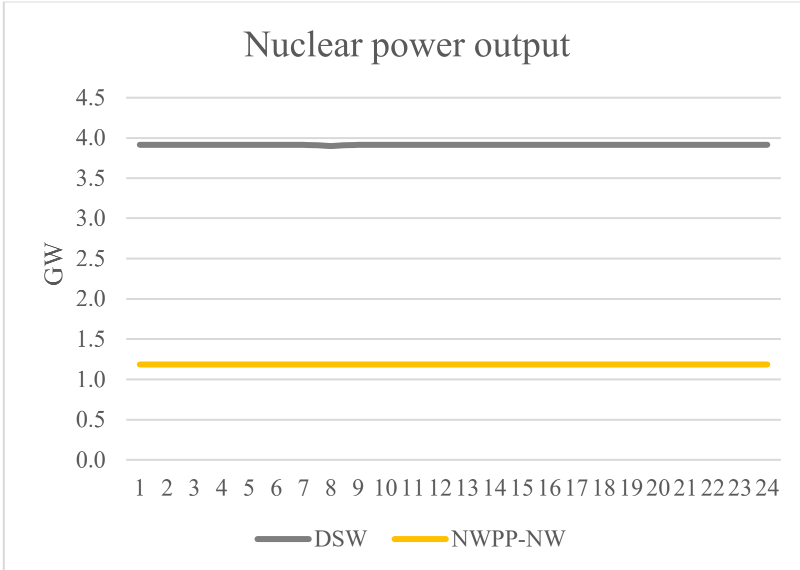


Figure 3-63. WI 2030 HW daily nuclear generation profile by region

Figure 3-64 illustrates the breakdown of coal generation in the WI 2030 HW case by region.

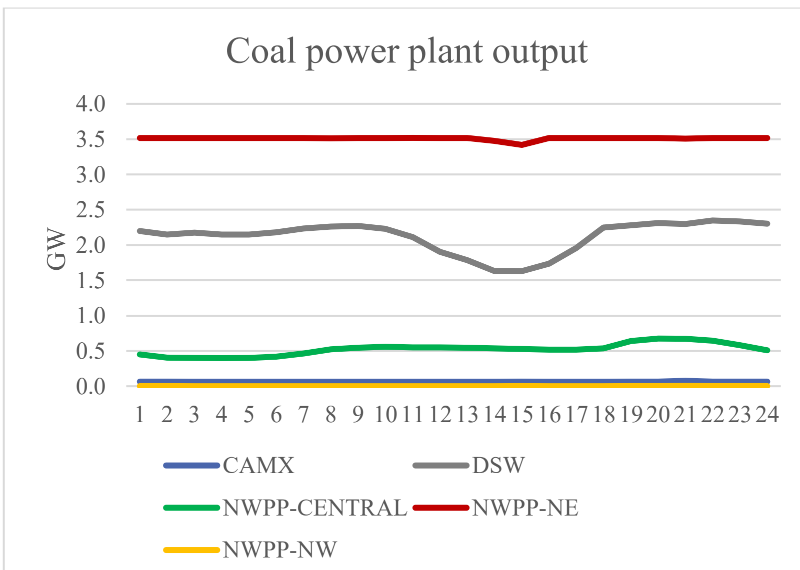


Figure 3-64. WI 2030 HW daily coal generation profile by region

Figure 3-65 illustrates the breakdown of gas and other thermal generation in the WI 2030 HW case by region. Compared to the gas and other thermal generation in WI 2030 HS case, the output from gas and other thermal units is considerably lower in HW because of the lower load consumption.

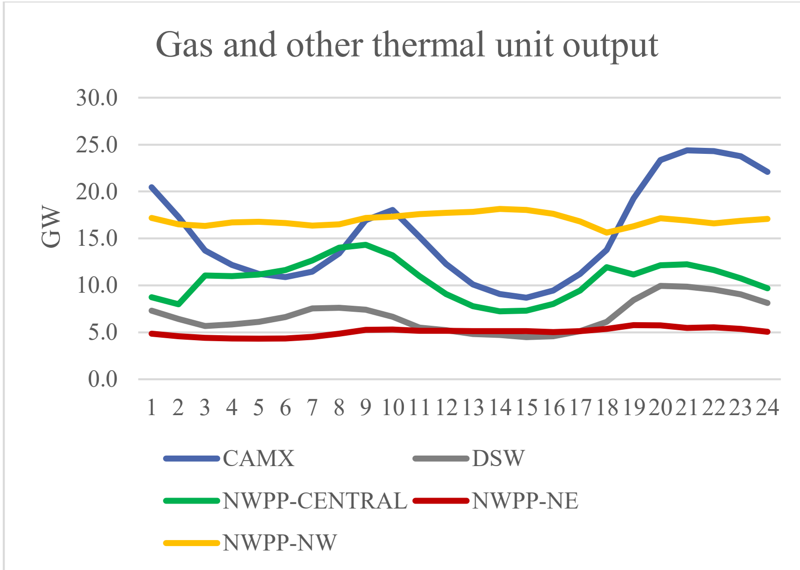


Figure 3-65. WI 2030 HW daily gas and other thermal generation profile by region

Figure 3-66 illustrates the breakdown of hydro generation in the WI 2030 HW case by region.

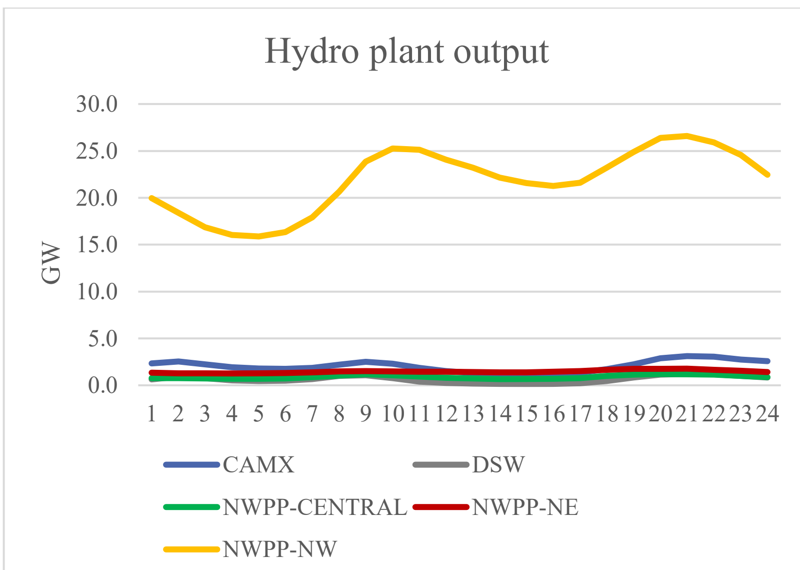


Figure 3-66. WI 2030 HW daily hydro generation profile by region

3.3.5 High Renewable Penetration Impact Analysis

In WI 2030 electric base cases, the retirement of coal power plants and the increase in renewable generation capacity have contributed to a higher renewable penetration compared to WI 2020 baseline. Known for the uncertainty and low inertia, high penetration of renewable sources may introduce a significant impact on the reliability and resiliency of the bulk grid.

To investigate the potential impact of high renewable energy penetration on the future WI electric grid, the project team proposed to employ both model-based and data-driven approaches to evaluate the voltage stability and system load margin. Voltage stability aims to assess the impact of renewable generation fluctuation on voltage magnitude, which can provide useful information to system operators to identify vulnerable buses in the system [49]. System load margin can estimate the level of load growth that the grid can support considering stability and security constraints [50].

Due to the stochasticity and uncertainty of renewable energy and flexible load, the voltage stability and system load margin are not deterministic. Therefore, stochastic approaches should be employed, which are well known for their high computational complexity. To relieve the computational burden, the renewable penetration impact analysis was conducted on the mini WECC system instead of the whole WI system. The mini WECC system is a simplified transmission system model that aggregates key generation and transmission data of the original whole WI system. The mini WECC system contains 243 buses and 143 generators [51]. The mini WECC system is shown in **Figure 3-67**.

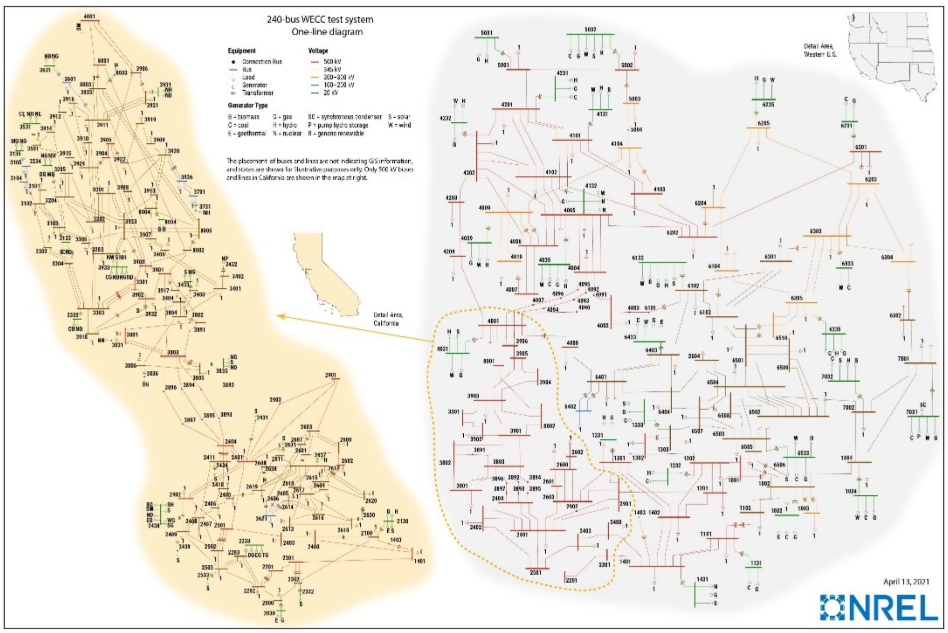


Figure 3-67. Mini WECC system diagram

For voltage stability analysis, existing model-based solutions are computationally prohibitive with the continuation power flow (CPF) calculation tool under uncertain conditions. Existing data-driven approaches do not account for these uncertainties and lack of interpretability.

In this regard, the project team employed the probabilistic power flow approach (PPF) to model the uncertainty of high renewable energy penetration. PPF is not effective for solving very large power systems. For the mini WECC system with 243 buses, PPF can efficiently analyze the voltage stability. The workflow is illustrated in **Figure 3-68**.

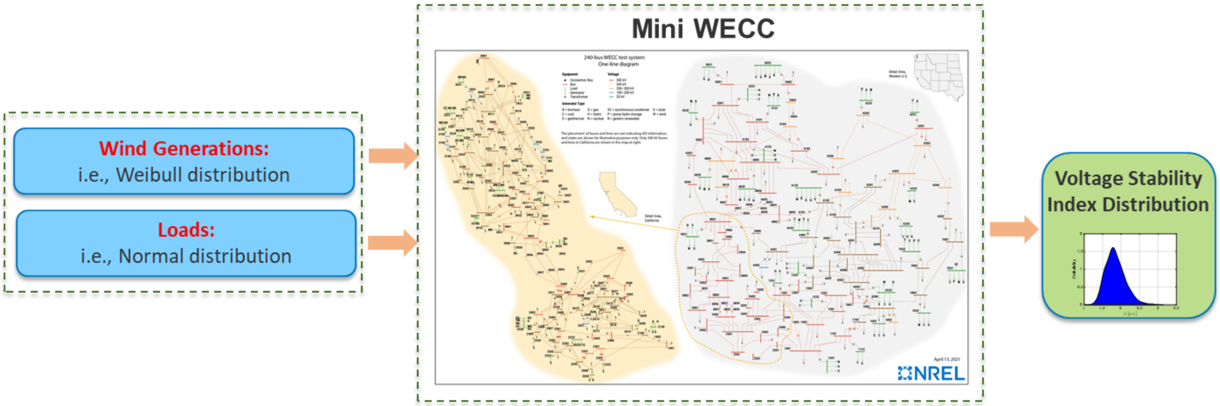


Figure 3-68. Voltage stability assessment using mini WECC system

To model voltage stability, the voltage magnitude V is modeled as a function of active power injection P and reactive power injection Q in the power network, as shown below.

$$V = M_{pf}(P, Q)$$

The uncertainty is modeled leveraging time-series load and generator output data, as can be described in the equation below and **Figure 3-69**.

$$\mathcal{M}_{gp} \sim \mathcal{GP}\left(m(\boldsymbol{x}), k(\boldsymbol{x}, \boldsymbol{x}'; \boldsymbol{\theta})\right)$$

where $\boldsymbol{x}$ denotes uncertain inputs, including both loads and generators. $m(\boldsymbol{x})$ denotes the mean function, $k(\boldsymbol{x}, \boldsymbol{x}'; \boldsymbol{\theta})$ denotes the kernel function with parameter $\boldsymbol{\theta}$ that describes the similarity of $(\boldsymbol{x}, \boldsymbol{x}')$.

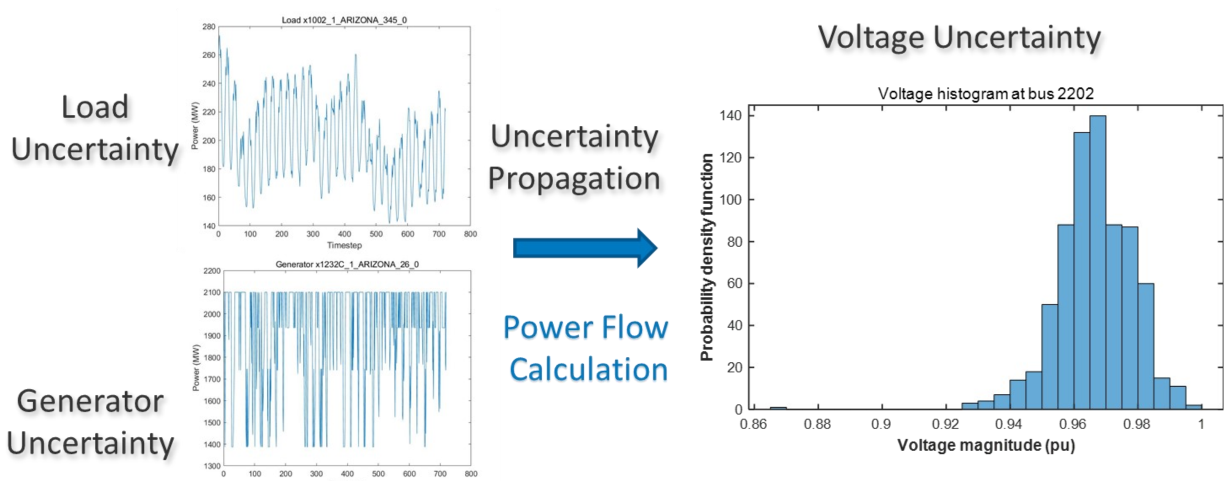


Figure 3-69. Uncertainty modeling

The employed PPF approach has the following features:

- Data-driven, the input and model information are not required.
- Non-parametric model is employed, which uses less stringent assumptions and is more robust to outliers
- Uncertainty measure over predictions
- High accuracy with few samples

The proposed PPF method is tested on the mini WECC system, where 135 uncertain loads and 130 uncertain generators are considered. For uncertainty modeling, 720 samples are used as historical data. **Figure 3-70** and **Figure 3-71** demonstrated the voltage violation results on a selected bus.

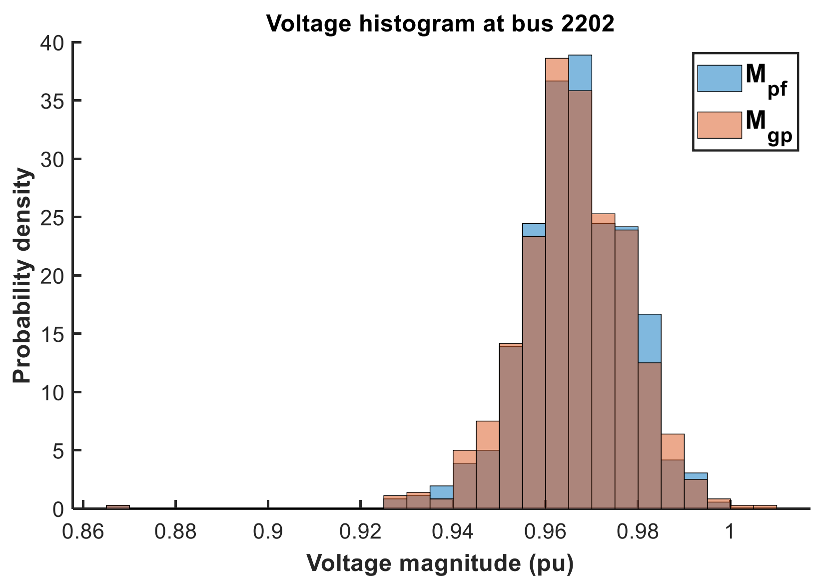


Figure 3-70. Voltage histogram at one selected bus in mini WECC system

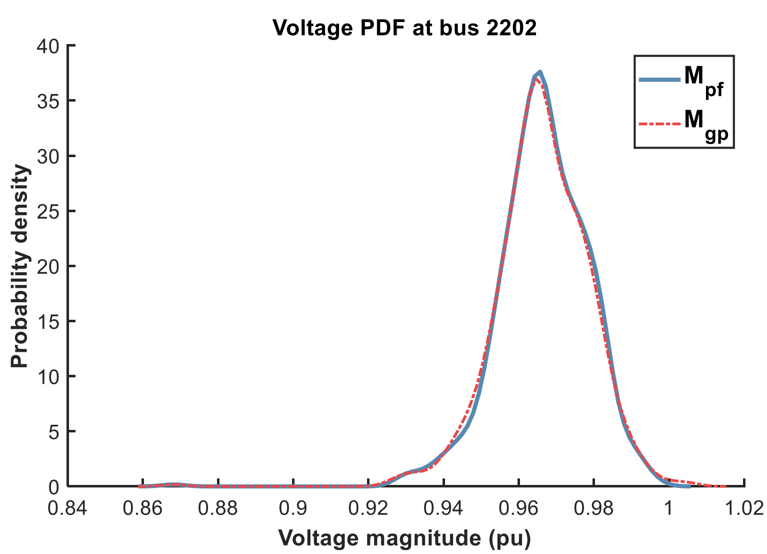


Figure 3-71. Evaluated voltage magnitude based on probabilistic power flow

Based on the simulation results in **Figure 3-70** and **Figure 3-71**, the voltage magnitude at this bus mainly varies between 0.92 p.u. to 1.0 p.u. The lowest and highest voltage magnitudes are 0.86 p.u. and 1.02 p.u., respectively. Note that these extreme voltage magnitudes are rare, thus it can be concluded that high renewable penetration will not influence the voltage stability at this bus.

For system load margin analysis, massive CPF calculations with Monte Carlo simulation (MCS) are required, which is time-consuming. Similarly, the computational burden can be relieved by testing on the smaller mini WECC system.

The project team constructed a data-driven computationally cheap probabilistic surrogate model to replace the CPF module for load margin assessment. Kernel SHAP [52], a method that uses a special weighted linear regression to compute the importance of features, is employed to identify the critical factors that affect load margin for preventative control. The diagram of the method is shown in **Figure 3-72**.

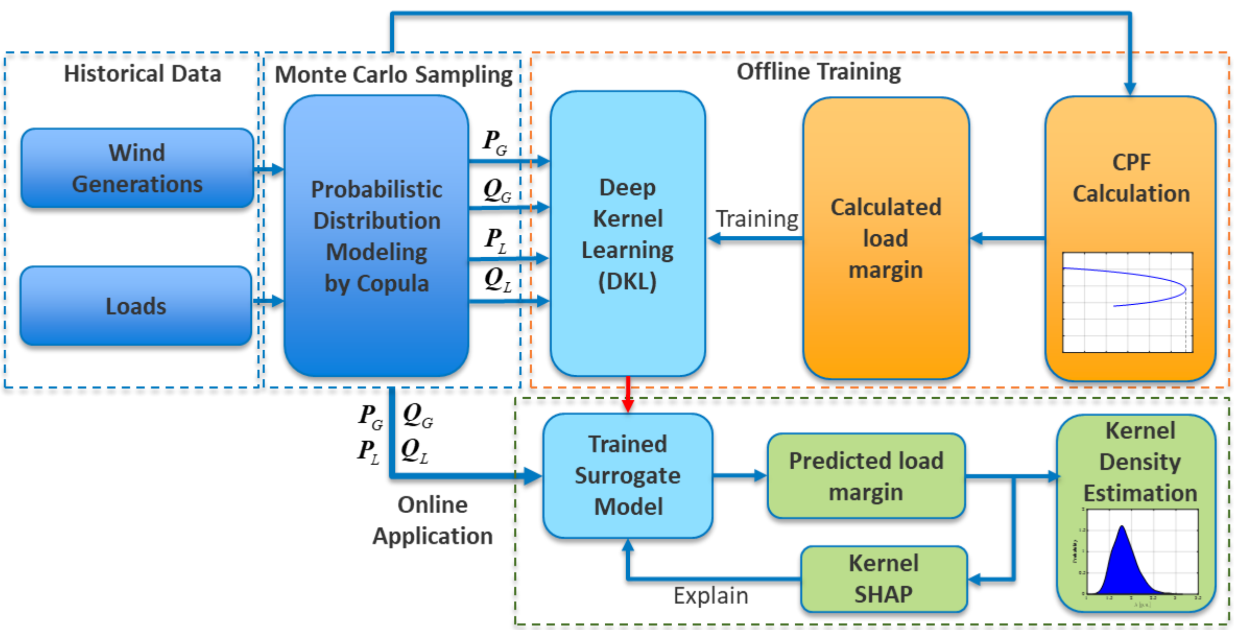


Figure 3-72. Diagram of the proposed load margin analysis

In **Figure 3-73**, the core is the Deep Kernel Learning (DKL) module. DKL, illustrated in **Figure 3-73**, merges deep neural network and Gaussian process regression, leading to a good capacity of nonlinear representation extraction and less requirement of training samples.

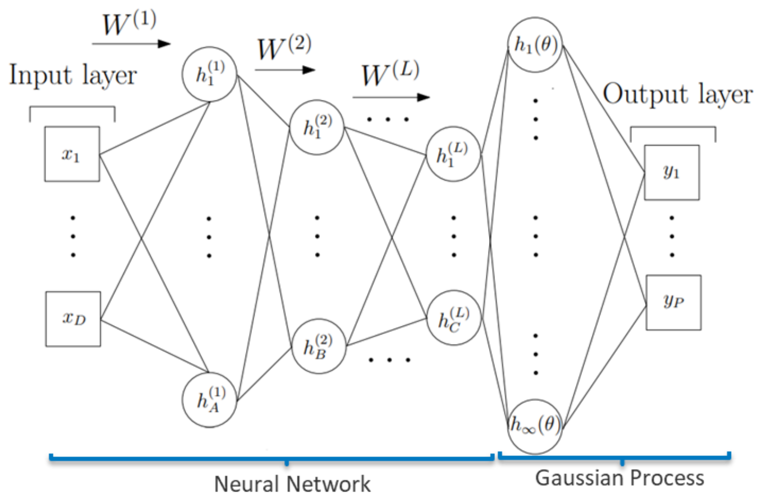


Figure 3-73. Diagram of Deep Kernel Learning

Load margin is affected by many random resources, and it is critical to identify the most critical factors that can inform proper control actions. Shapley value for sensitivity analysis. Preliminary simulation results are shown in **Figure 3-74** and **Figure 3-75**.

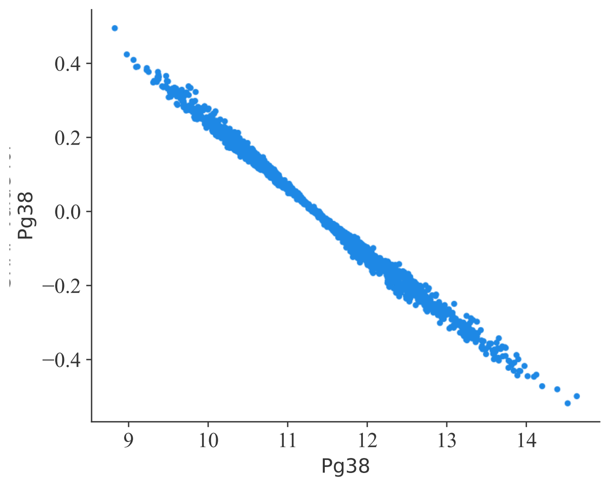


Figure 3-74. Impact of one selected conventional generator on system load margin

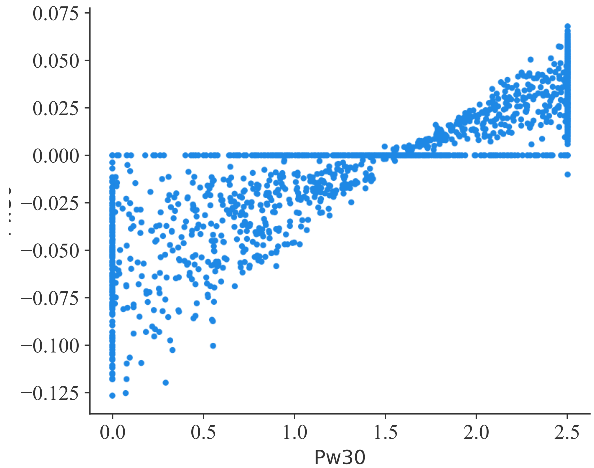


Figure 3-75. Impact of one selected wind generator on system load margin

As shown in **Figure 3-74**, this conventional generator has a negative impact on load margin (i.e., a negative slope). However, in **Figure 3-75**, the pattern is different, meaning that this wind generator has positive impact on load margin. Therefore, this result indicates that increasing the capacity of this wind generator can help the system in supporting more load.

3.3.6 Key Finding

The WI 2030 HS and HW base cases validate the feasibility of the projected load growth and generation mix change. In addition to the impact assessment of high renewable penetration demonstrated in **Section 3.3.5**, another key finding is the impact of changing generation mix on the power flow through important WECC paths.

WECC defined important transmission corridors as paths to model and understand congestion and reliability. A detailed WECC path definition can be found in [53]. Take WI 2030 HS base case as an example, the WECC path flows of selected paths at peak hour period are compared with the recorded path flows in 2021 summer, the results are listed in **Table 3-23**. Observed from **Table 3-23** it is obvious that the WECC path flows may become very different in 2030, e.g., on path no. 8, the path flow is positive in 2021 peak hours, while the flow becomes negative (i.e., reverse power flow) in 2030 peak hours.

Table 3-23. HS peak hour power flow comparisons on selected WECC paths

Path	2021				2030			
No.	17:00	18:00	19:00	20:00	17:00	18:00	19:00	20:00
1	184.1	246.9	128.5	27.0	290.5	298.0	307.7	314.5
3	-2063.1	-1909.6	-1890.2	-1538.8	-2046.4	-2110.8	-2062.1	-2010.3
8	166.4	135.4	192.0	258.2	-647.2	-621.4	-554.2	-519.6
14	-122.1	-304.1	-153.4	-71.3	-1080.8	-867.2	-621.2	-435.2
26	4910.9	4998.6	4395.8	3358.5	-163.1	194.4	1167.3	2216.6
31	89.4	44.9	21.4	-106.4	-384.0	-268.5	-117.9	12.9
35	-268.5	-194.0	-231.9	-228.4	290.7	184.8	2.7	-181.8
46	-4705.4	-4146.7	-4157.9	-4306.3	-3895.3	-3383.5	-2759.1	-2060.8
49	3027.5	2959.6	3229.0	3340.4	-620.0	-242.0	350.6	981.0
65	2788.1	2917.2	3039.1	3049.5	2788.1	2788.1	2788.1	2788.1

Path	2021				2030			
66	2449.5	2180.3	2223.8	1958.7	-381.4	-169.3	24.6	215.4
78	8.6	33.2	23.2	17.9	-309.9	-228.5	-87.7	48.2
79	-27.3	-39.6	-49.2	-88.8	-72.6	-43.6	10.9	60.2

Three critical WECC paths are selected for further investigation. These three paths are highlighted in **Figure 3-76**, and the path definitions are given below:

- Path 26 Northern-Southern California: Consists of three 500 kV lines. Transfer limit is 4000 MW from North to South, and 3000 MW from South to North.
- Path 65 Pacific DC Intertie (PDCI): PDCI line is a ±500 kV DC multi-terminal system. The transfer limit is 3220 MW from North to South, and 3100 MW from South to North.
- Path 66 California-Oregon Intertie (COI): Consists of three 500 kW lines. The transfer limit is 4800 MW from North to South, and 3675 MW from South to North.

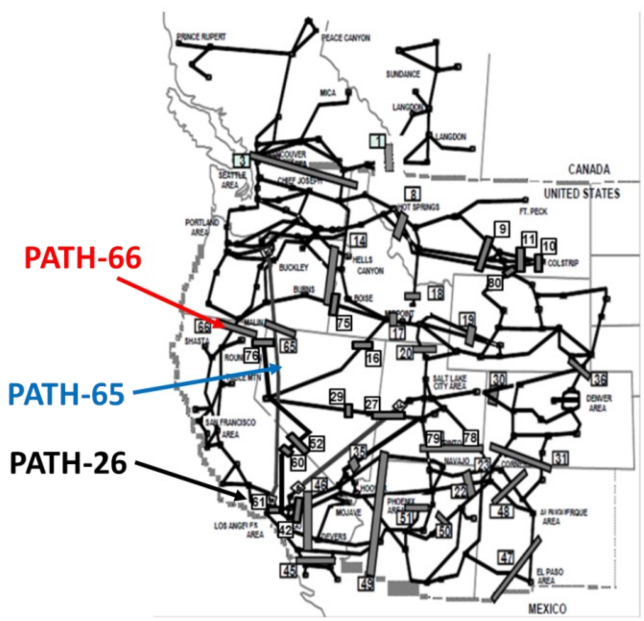


Figure 3-76. Definition of Selected WECC Paths

In WI 2030 HS case, the daily power flows in these three selected paths are shown in **Figure 3-77**. The changes in the 2030 WI resource mix result in significant changes in path flow patterns. As shown in **Figure 3-77**, the growing solar capacity in California leads to reverse power flow in Path 25 and Path 66 in the early afternoon hours. Path 65 is a DC path so the power flow direction will not be reversed. In summary, the increasing renewable generation capacity will alter existing path flow patterns and influence existing protection schemes.

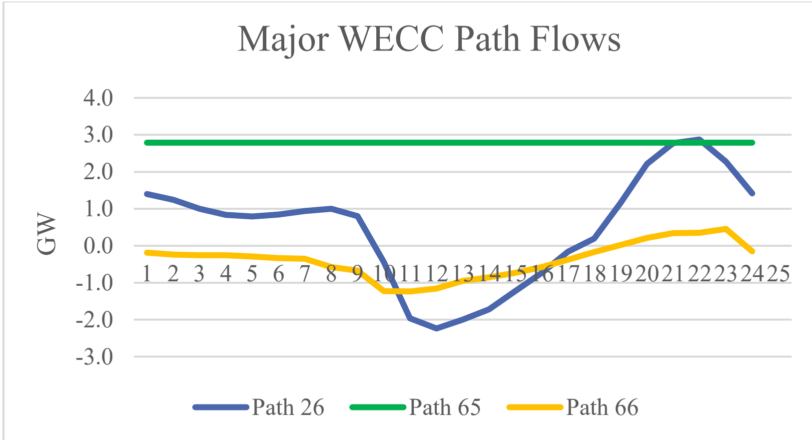


Figure 3-77. Path flows in WI 2030 HS case

3.4 National Natural Gas Base Case

The main focus is the development of a baseline of the interconnected national electric and natural gas sectors from 2022 to 2030. The major tasks completed by the National Energy Technology Laboratory (NETL)/Argonne National Laboratory (ANL) team included in Task 3.0 in the SOW are summarized below. Work on this task was performed utilizing electricity and natural gas system Critical Energy Infrastructure Information (CEII) along with other proprietary and restricted access datasets provided by other federal agencies and industry.

This project is part of the DOE's Grid Modernization Initiative (GMI) and aims to answer the following questions

1. Will the system with far more capacity but with much less inertia still provide on-time electricity?

2. Will increasing gas-electric interdependence lead to system compromise?

3. While not regular, under long-duration weather events, will the generating fleet prove resilient?

Answering these questions required the integration and use of models from across the partner labs engaged on the NTRR GMI project. The cross-lab NTRR GMI project has several target areas with different labs responsible for different areas. This document describes the joint analysis from NETL and ANL to model natural gas deliverability and the interaction between the electricity and natural gas sectors. Despite the regional/interconnection level focus of most of the participants, NETL and ANL modelling for electricity and natural gas cover the entirety of the interconnected North American electricity and natural gas networks, and thusly the entirety of the three distinct North American power system interconnections since natural gas flows across regions and power sector demand in one interconnection can influence the gas supply and storage situation thereby affecting other regions. Additionally, while other portions of the NTRR analysis are based on a snapshot period or particular year, modelling performed by NETL and ANL spans an hourly temporal horizon from 2022 to 2030 to enable capture of full seasonal natural gas storage cycles, impacts of infrastructure changes in both the natural gas and electric systems, and representation of dynamics such as the diurnal nature of renewable energy systems, demand changes, and counterposed peak seasons for electricity demand (summer) and natural gas demand (winter).

3.4.1 Methodology

The analysis described in this section joined together three commercial software packages and an open platform model. NETL utilized the three commercial platforms: Hitachi Energy's PROMOD IV, an electricity system dispatch (production cost) model, Siemens PSS/E, a transmission system analysis model, and Deloitte's MarketBuilder, a generalized equilibrium model configured in this case for natural gas markets and infrastructure. ANL's NGFast model was used to evaluate potential natural gas delivery constraints for a scenario configuration of gas supply from production and storage, flows, and demands from storage and various sectors including gas-fired electricity unit dispatch.

Production cost models generally take electric load growth as an input and determine the electric power dispatch using a security constrained least cost optimization (after allowing for "must-run" generators) and assume adequate fuel supply and natural gas delivery, whereas MarketBuilder can endogenously escalate natural gas production and delivery infrastructure to meet economically assumed natural gas demand.

Hitachi Energy's PROMOD IV is a security constrained economic dispatch software. The software enables the input of time-based data on fuel pricing, renewable energy profiles, electricity demand, etc., and detailed unit level generator and system inputs to determine the effects of transmission congestion, generator availability, bidding behavior, and load growth on market prices. The underlying transmission system topology in the tool is built upon regional CEII power flow cases. While fuel prices are typically an input schedule to PROMOD IV, natural gas prices used result from the clearing price determined in MarketBuilder.

Siemens' PSS/E software is a physics-based transmission planning and analysis software. The software enables the input of power system data including generation, load, transmission, and transmission elements. A user definable output from PROMOD IV is the transmission topology solution, including generator output levels, individual load levels, and economic transmission flows, at any selected study hour in PSS/E format. These PROMOD IV outputs represent a change file to regional CEII power flow cases that can be utilized to verify and validate dispatch results for physical feasibility. [54]

MarketBuilder models systems from a fundamentals perspective of supply, demand, and infrastructure. Applied to the natural gas market, the baseline case includes North America production basins, gas processing, pipeline transmission, storage, and demand by sector. As an equilibrium model, prices throughout the network are such that supply and demand volumes are balanced at each pricing hub. While demand for the residential and commercial ("core") and industrial sectors have price elasticities, the volume for the power sector gas demand is derived from the multi-fuel competitive dispatch performed in PROMOD IV using gas market clearing prices from MarketBuilder.

NGFast focused on volumetric gas flows throughout the continental pipeline system. Configured for inputs such as production, storage injection/withdrawal, and demand, NGFast can identify constraints or violations in the pipeline system. Disruptions such as pipeline outage or breakage can be simulated with volumes re-routed and the associated system impacts computed.

Through this project, NETL and ANL have developed algorithms through which the models inform each other, which allows both projecting necessary growth in production and infrastructure as well as testing the impact of constraints and stresses. The model integration methodology occurs through an iterative process among the four models, with PROMOD-MarketBuilder co-optimizing electricity and natural gas market dispatch/flows, co-optimized electricity results passed to PSS/E for physical validation of electricity system results through a change file to regional CEII power flow models, and co-optimized natural gas results passed to NGFast for physical validation of natural gas flow results. An initial run of

MarketBuilder outputs a set of regional natural gas prices that serve as an input for PROMOD which creates a set of regional power sector natural gas demands based on the competitive economic dispatch of gas-fired units versus other generation. These regional power sector gas demands are then used again in the MarketBuilder model to converge the natural gas prices until an equilibrium state of the supply chain is obtained. This process occurs iteratively until results from MarketBuilder and PROMOD achieve convergence, a situation in which the gas prices and power sector gas demands from both models are consistent. The model integration methodology is illustrated in **Figure 3-78**.

3.4.1.1 MarketBuilder Model setup

MarketBuilder was configured with a derivative of the World Gas Model to cover North America for the study horizon period. Natural gas demands by major sector (residential, commercial, industrial, and power) were informed by EIA historical data and aligned with the 2021 AEO reference case for projected periods. Power sector demands initially set to EIA values were then replaced with the power sector demands resulting from the PROMOD competitive dispatch solution in the model iteration process. While not the direct permitting entity, the Federal Energy Regulatory Commission (FERC) reviews and tracks pipeline applications, and their data on pipeline projects[4] combined with information from S&P Capital IQ Pro and individual company press releases and filings provided the basis for updates to natural gas infrastructure.

NGFast initial configuration data are derived from EIA natural gas pipeline and state flow information. Converged cases of PROMOD IV and MarketBuilder provide replacement or additional data. For example, unit-level gas consumption from gas-fired electric generating units resulting from the PROMOD IV dispatch are used as inputs to NGFast. Production, major pipeline and corridor flows, storage activity, and demand (including liquified natural gas exports) from MarketBuilder are also used in the overall infrastructure framework within NGFast. NGFast can then identify physical pipeline constraints or infeasible configurations, and any such issues provide a basis for modification of either PROMOD IV or MarketBuilder assumptions or constraints to avoid the problems found using NGFast.

[4] https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-pipelines

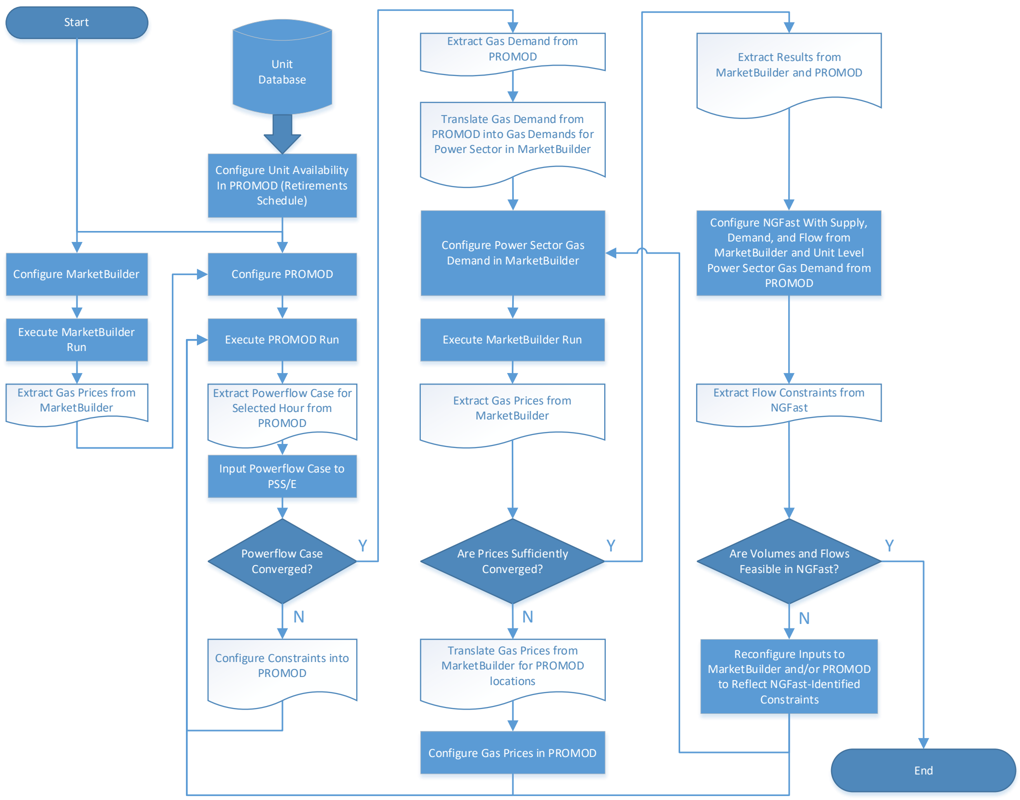


Figure 3-78. PROMOD-MarketBuilder-NGFast-PSS/E Integration Methodology

3.4.2 Accomplishments, Findings, Decisions, and Conclusions

Final co-simulation iterations between PROMOD and MarketBuilder were completed.

3.4.2.1 Task 3.1: Calculate baseline regional power sector gas demands from present day through 2030 by applying security constrained economic dispatch

STATUS: Completed

1. Gas scenario assumed normal (50/50) system demand conditions for the bulk power system and non-power natural gas demands on the pipeline system across the modeling horizon.

2. Multiple iterations have been conducted to validate the modeling results and ensure that gas and electric side compensation (from line pack, storage, transmission, etc.) are accurately reflected (see preliminary monthly aggregated results below). The results below (**Figure 3-79**) indicate a compound annual growth rate of peak power month natural gas fired power generation of 1.8% in ERCOT, 0.8% in WECC, and 0.7% in the EI.

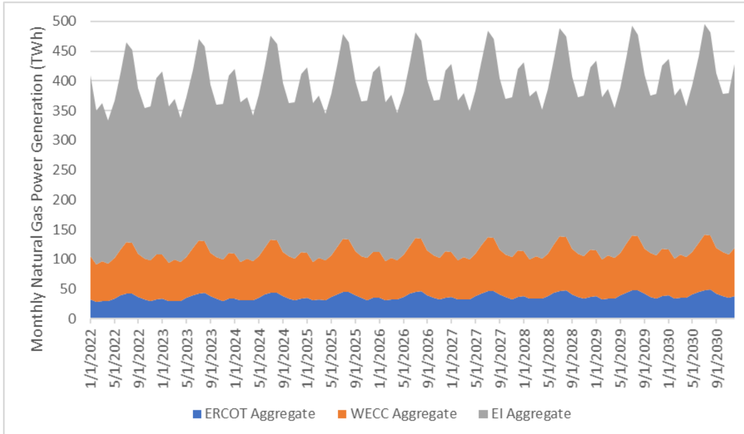


Figure 3-79. Preliminary Compound Annual Growth Rate of Peak Power Month Natural Gas Fired Power generation.

3.4.2.2 Task 3.2: Compile demand projections for the Deloitte's MarketBuilder® North American Gas Model

3.4.2.2.1 PROMOD Analysis

1. Calculated a baseline regional power sector gas scenario from present day through 2030 by applying security constrained economic dispatch. The PROMOD model was used to compile demand projections by utilizing data from NERC. This data was then used as an input for MarketBuilder to project the topology of the future natural gas pipeline network across the interconnected North American system along with regional natural gas prices that will be seen by market participants in future years. The MarketBuilder model used data from the EIA for natural gas projected demand and FERC and S&P Capital IQ Pro for capacity expansions and new pipeline developments.

2. Assumed normal system demand conditions for the bulk power system and non-power natural gas demands on the pipeline system across the modeling horizon. The PROMOD model was used to represent the projected electric network by 2030 and MarketBuilder represents the projected natural gas supply chain by 2030.

3. Completed the Baseline Scenario when both models (MarketBuilder and PROMOD) achieved convergence on natural gas prices and power sector demand numbers. The following sections showcase the results used as the Baseline Scenario for this project.

Achieved the PROMOD baseline scenario used by using models updated according to the National Energy Technology Laboratory (NETL) Quality Guidelines for Energy System Studies (QGESS): Economic Unit Commitment and Dispatch Modeling Guidelines for NETL Studies Version 3.0 [55] and modified as necessary for the study. The baseline scenario has a 50/50 winter demand assumed in each region, along with Anticipated capacity and retirements updated to match capacities as outlined in the 2020 NERC LTRA [10] shown in **Table 3-24**. This baseline was used as a reference for other extreme weather scenarios developed.

Table 3-24. 2020 LTRA Anticipated Summer Capacity.

FUEL TYPE CAPACITIES (Nameplate Value)	Unit	2021	2025	2030
MISO				
Coal	MW	53,771	47,516	43,866
Petroleum	MW	2,737	2,507	2,507
Natural Gas and Other Gases	MW	65,396	64,278	60,802
Biomass	MW	438	372	297
Solar	MW	385	1,089	1,089
Wind	MW	4,558	4,542	4,464
Geothermal	MW	0	0	0
Conventional Hydro	MW	1,539	1,331	1,331
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	2,686	2,654	2,654
Nuclear	MW	12,982	12,169	12,169
Other	MW	35	35	35
ISO-NE				
Coal	MW	533	533	533
Petroleum	MW	6,567	5,859	5,859
Natural Gas and Other Gases	MW	15,850	14,376	14,376
Biomass	MW	851	832	832
Solar	MW	149	200	200
Wind	MW	183	185	185
Geothermal	MW	0	0	0
Conventional Hydro	MW	1,167	1,172	1,172
Run of River Hydro	MW	131	131	131
Pumped Storage	MW	1,788	1,854	1,854
Nuclear	MW	3,321	3,321	3,321
Other	MW	6	6	6
NYISO				
Coal	MW	0	0	0
Petroleum	MW	8,297	6,872	6,872
Natural Gas and Other Gases	MW	18,095	18,060	18,060
Biomass	MW	321	321	321
Solar	MW	16	27	27
Wind	MW	297	407	407
Geothermal	MW	0	0	0
Conventional Hydro	MW	3,317	3,317	3,317
Run of River Hydro	MW	411	411	411
Pumped Storage	MW	1,407	1,407	1,407
Nuclear	MW	3,343	3,343	3,343
Other	MW	0	0	0

FUEL TYPE CAPACITIES (Nameplate Value)	Unit	2021	2025	2030
PJM				
Coal	MW	53,683	51,391	51,391
Petroleum	MW	11,432	11,432	11,432
Natural Gas and Other Gases	MW	82,519	92,389	92,389
Biomass	MW	1,054	1,104	1,104
Solar	MW	2,794	4,140	4,140
Wind	MW	1,754	1,829	1,829
Geothermal	MW	0	0	0
Conventional Hydro	MW	3,072	3,095	3,095
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	5,229	5,229	5,229
Nuclear	MW	32,626	32,626	32,626
Other	MW	20	25	25
SERC				
Coal	MW	52,407	51,396	50,298
Petroleum	MW	3,543	3,543	3,320
Natural Gas and Other Gases	MW	98,170	99,763	105,512
Biomass	MW	918	877	842
Solar	MW	5,102	8,976	9,861
Wind	MW	456	456	456
Geothermal	MW	0	0	0
Conventional Hydro	MW	10,064	10,106	10,136
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	6,576	6,760	6,760
Nuclear	MW	29,482	31,684	31,694
Other	MW	11,115	12,036	12,088
SPP				
Coal	MW	23,172	23,172	23,172
Petroleum	MW	1,440	1,440	1,440
Natural Gas and Other Gases	MW	29,148	29,148	29,148
Biomass	MW	31	51	51
Solar	MW	172	191	191
Wind	MW	5,410	5,445	5,445
Geothermal	MW	0	0	0
Conventional Hydro	MW	4,767	4,767	4,767
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	363	363	363
Nuclear	MW	1,944	1,944	1,944
Other	MW	280	280	280
ERCOT				

FUEL TYPE CAPACITIES (Nameplate Value)	Unit	2021	2025	2030
Coal	MW	13,995	13,995	13,995
Petroleum	MW	0	0	0
Natural Gas and Other Gases	MW	49,683	49,683	49,683
Biomass	MW	169	169	169
Solar	MW	7,700	12,161	12,161
Wind	MW	8,100	9,096	9,096
Geothermal	MW	0	0	0
Conventional Hydro	MW	470	470	470
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	0	0	0
Nuclear	MW	4,973	4,973	4,973
Other	MW	0	0	0
WECC-US				
Coal	MW	25,048	23,494	20,474
Petroleum	MW	827	827	827
Natural Gas and Other Gases	MW	81,767	81,876	81,543
Biomass	MW	1,580	1,624	1,624
Solar	MW	13,335	15,685	15,707
Wind	MW	4,191	4,707	4,707
Geothermal	MW	3,416	3,426	3,426
Conventional Hydro	MW	31,535	31,601	31,595
Run of River Hydro	MW	0	0	0
Pumped Storage	MW	3,429	3,429	3,429
Nuclear	MW	7,590	5,590	5,590
Other	MW	1,132	1,413	1,413

4. Extracted preliminary results for the dispatch model. Dispatch results provide an outlook at hourly unit dispatch model results, aggregated up to provide a high-level picture of system performance across the study period. Results are aggregated up by area, and by year, compare regional local marginal price (LMP), emissions, capacity factors, and fuel usage.

5. Extracted results for the Regional System LMP, which are shown below in

6. **Table** 3-25Error! Reference source not found.**.** The following tables provide a look at regional on peak average LMP for winter peak, and summer peak[5]. Prices in WECC and California Independent System Operator (CAISO) areas rise in the summer months during the study period, reaching above $100 by 2030. These price increases during summer months are driven largely EUE, shown in PROMOD as modeled emergency energy. Prices in ERCOT show a similar trend, rising in summer months, driven by EUE in the Houston and South zones. **Table 3-26** and **Table 3-27** detail the projected EUE for each impacted transmission zone on a month of occurrence basis.

[5] Non-coincident peaks

Table 3-25. Regional On-peak average LMP by season ($/MWh)

		UOM	2022	2023	2024	2025	2026	2027	2028	2029	2030
PJM	Winter	$/MWh	$28.21	$29.18	$30.07	$30.82	$31.36	$31.63	$32.05	$32.75	$33.50
	Summer	$/MWh	$26.80	$27.52	$28.32	$29.53	$30.19	$30.43	$31.11	$32.02	$32.82
ISO-NE	Winter	$/MWh	$39.62	$42.99	$42.13	$43.03	$42.58	$41.03	$42.13	$42.93	$44.77
	Summer	$/MWh	$28.34	$28.98	$30.12	$31.25	$32.01	$31.90	$32.53	$33.54	$34.52
NYISO	Winter	$/MWh	$38.05	$39.35	$39.94	$40.65	$41.05	$40.43	$40.87	$41.55	$42.38
	Summer	$/MWh	$34.76	$35.10	$36.69	$37.84	$38.27	$37.76	$39.37	$40.77	$41.18
SERC	Winter	$/MWh	$25.09	$25.72	$26.22	$26.68	$26.97	$27.34	$27.75	$28.21	$28.67
	Summer	$/MWh	$27.94	$29.05	$30.37	$31.31	$30.97	$32.54	$33.40	$34.69	$36.27
MISO	Winter	$/MWh	$25.43	$26.44	$27.34	$28.27	$29.20	$29.75	$30.37	$31.43	$32.19
	Summer	$/MWh	$25.68	$27.02	$27.83	$28.99	$29.99	$30.48	$31.61	$32.43	$33.40
SPP	Winter	$/MWh	$21.66	$22.83	$23.43	$24.50	$25.23	$25.57	$26.04	$26.93	$27.65
	Summer	$/MWh	$23.12	$24.54	$25.37	$26.48	$27.48	$27.95	$28.97	$29.60	$30.58
WECC	Winter	$/MWh	$39.96	$42.97	$44.82	$46.82	$48.83	$50.28	$52.97	$56.44	$59.18
	Summer	$/MWh	$48.83	$54.94	$57.54	$63.95	$71.44	$77.80	$87.64	$94.88	$103.80
CAISO	Winter	$/MWh	$47.59	$49.43	$51.64	$54.58	$57.27	$59.53	$62.34	$66.07	$68.14
	Summer	$/MWh	$58.98	$64.86	$67.68	$75.72	$84.44	$91.42	$101.87	$109.67	$118.16
ERCOT	Winter	$/MWh	$27.62	$28.92	$31.10	$31.53	$32.30	$27.45	$28.40	$29.57	$30.55
	Summer	$/MWh	$64.11	$73.96	$90.06	$93.54	$130.16	$168.73	$350.93	$495.26	$655.56

Table 3-26. Western Regional Projected Monthly EUE (GWh)

	Arizona	CAISO - Bay Area	CAISO - SCE	CAISO - SDGE	Central Valley	Imperial Irrigation District	LADWP
Jul-23	—	0.3	—	—	—	—	—
Jul-24	—	16.1	—	—	1.4	—	—
Jul-25	—	26.1	1.1	0.0	1.0	—	—
Aug-25	—	10.7	1.0	0.2	2.1	0.2	—
Jul-26	—	60.7	15.9	0.3	3.3	—	—
Aug-26	—	12.0	0.2	0.0	0.1	—	—
Jul-27	—	96.7	48.3	0.7	17.5	—	—
Aug-27	—	26.6	25.9	0.8	5.3	0.2	1.1
Jul-28	—	117.9	90.5	0.8	24.7	—	—
Aug-28	—	49.0	51.5	1.2	8.4	0.1	0.3
Sep-28	—	1.5	—	—	—	—	—
Jul-29	—	136.8	126.5	1.3	39.1	0.0	4.3
Aug-29	—	66.6	59.5	1.6	16.2	—	0.4
Sep-29	—	2.7	—	—	—	—	—
Jun-30	—	2.5	—	—	—	—	—
Jul-30	3.0	155.1	171.7	1.7	68.3	0.1	10.4

	Arizona	CAISO - Bay Area	CAISO - SCE	CAISO - SDGE	Central Valley	Imperial Irrigation District	LADWP
Aug-30	—	75.1	52.2	1.6	20.7	—	—
Sep-30	—	4.2	—	—	0.0	—	—

Table 3-27. ERCOT Regional Projected Monthly EUE (GWh)

	Houston	South
Aug-24	0.3	—
Aug-26	1.7	—
Aug-27	6.2	—
Jul-28	8.3	—
Aug-28	64.3	—
Jun-29	1.0	—
Jul-29	34.7	—
Aug-29	108.5	—
Jun-30	6.7	—
Jul-30	62.4	—
Aug-30	186.2	1.7

7. Extracted results for regional Nitrogen Oxides (NOx), Sulphur Dioxide (SO2) and carbon Dioxide (CO2) emissions, which are shown in **Figure 3-80, Figure 3-81,** and **Figure 3-82.**

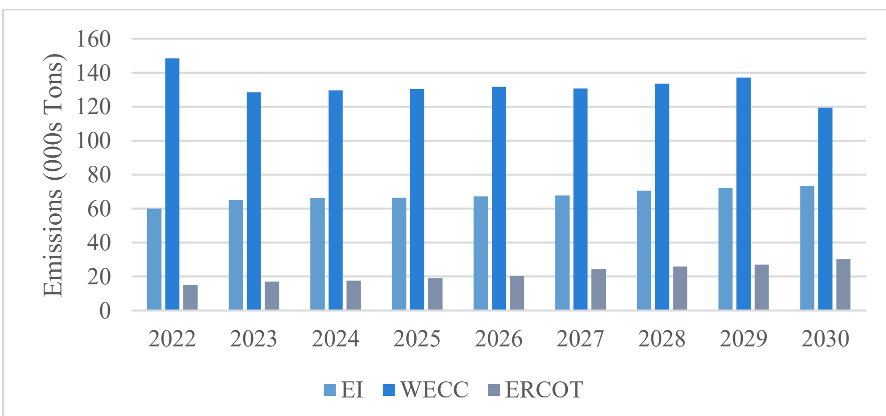


Figure 3-80. Total NOx Emissions by Region

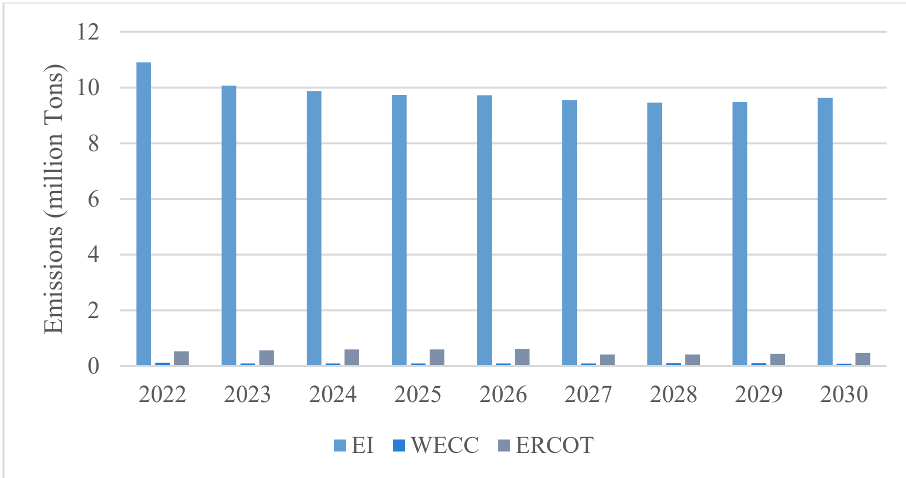


Figure 3-81. Regional SO2 Emissions

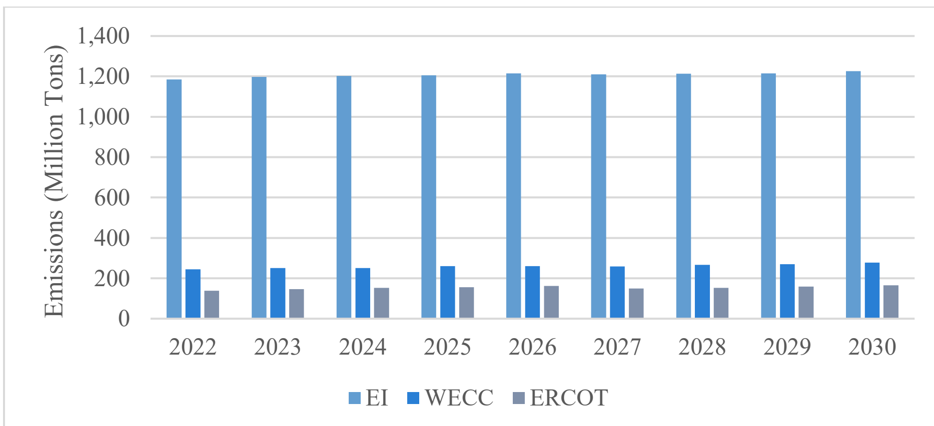


Figure 3-82. Total CO2 Emissions by Region

8. Output results for the generation capacity of each region, aggregated to the unit type**. Figure 3-83** shows the EI, **Figure 3-84** shows WECC, and **Figure 3-85** shows ERCOT. Nuclear, natural gas combined cycle (NGCC), and coal units has the three highest capacity factors in each region, with WECC showing increased capacity factors for other thermal generation, compared to EI and ERCOT.

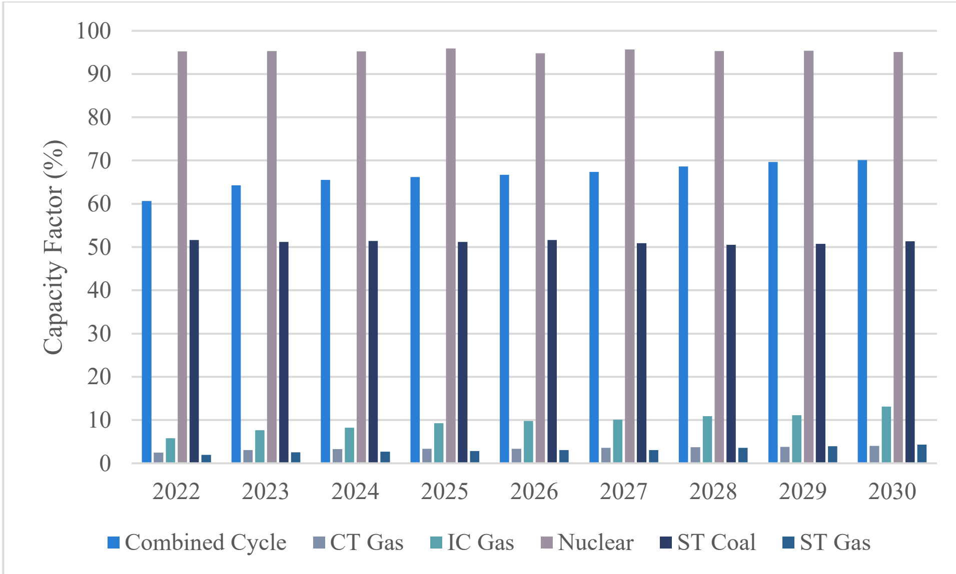


Figure 3-83. EI capacity factors by generation type (%)

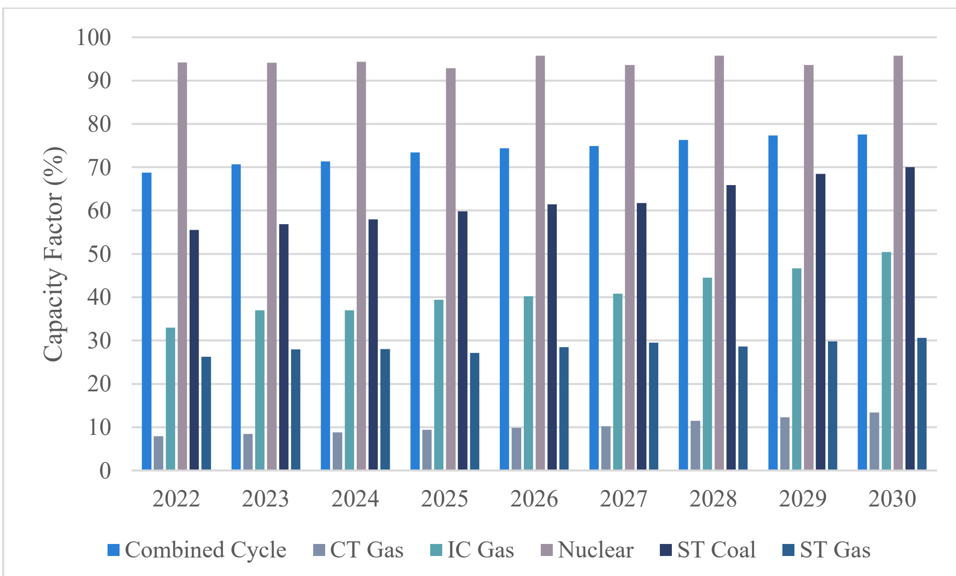


Figure 3-84. WECC capacity factors by generation type (%)

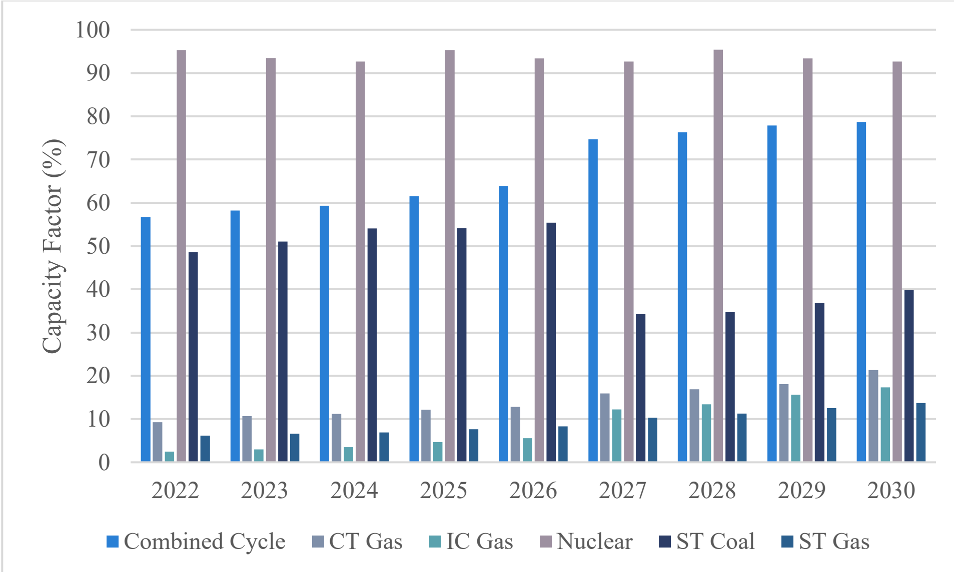


Figure 3-85. ERCOT capacity factors by generation type (%)

9. Extracted monthly natural gas utilization from the dispatch results. This information, shown in **Figure 3-86** is part of the information passed to the Marketbuilder model as part of the iteration process.

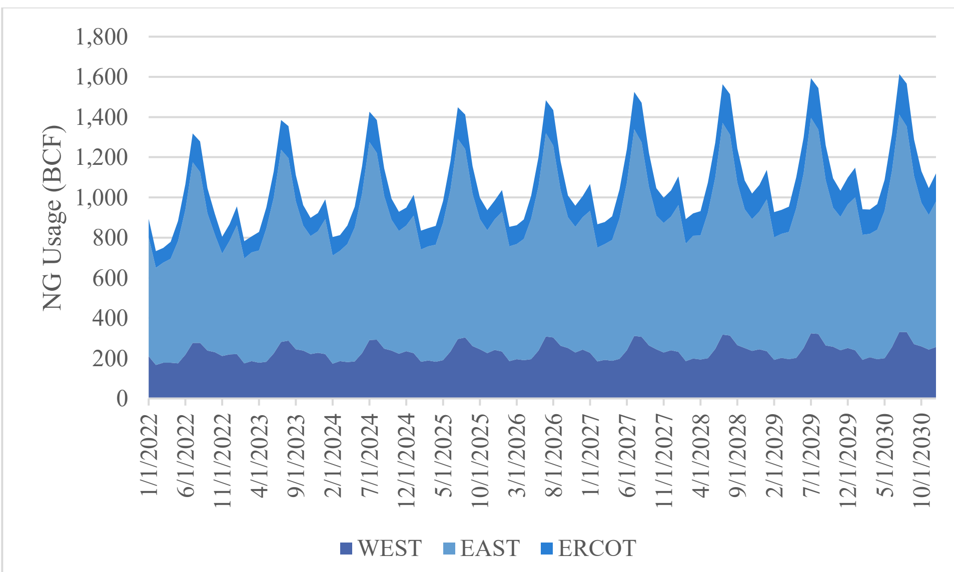


Figure 3-86. Regional monthly natural gas usage in Billion Cubic Feet (BCF)

3.4.2.2.2 MarketBuilder Analysis

1. MarketBuilder was used to model the natural gas infrastructure from present day to 2030. depicts the natural gas capacity expansions in (Bcf) modeled in the Baseline Scenario. This information was used to project natural gas demand to 2030.

2. **Figure 3-87** shows monthly natural gas demand by sector from the MarketBuilder model. The Industrial and Core (residential and commercial) sectors are derived from the 2021 AEO demand

projections while the Power sector demand are supplied by the gas-fired generation dispatch from the PROMOD model as part of the model iteration process.

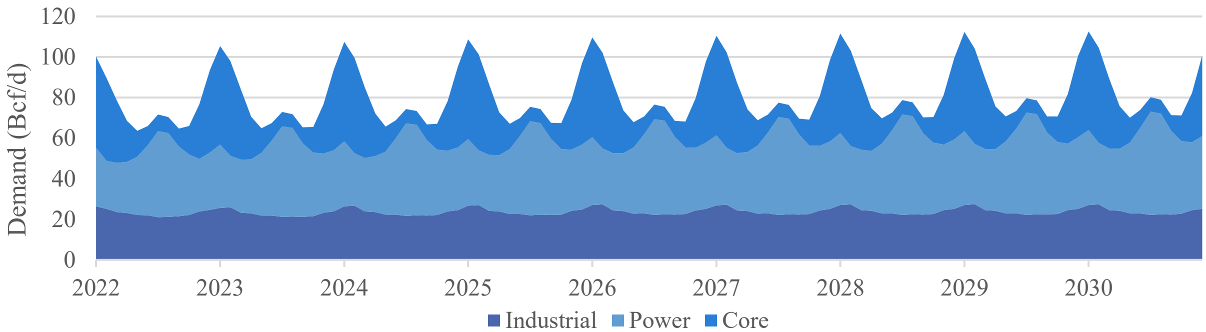


Figure 3-87. Natural Gas Demand by Sector

3. While the focus region is the expanded PJM territory, the national modeling still included the Northeast, and that region remains the area within the country with the greatest natural gas deliverability challenges and consequently highest natural gas prices. **Figure 3-88** shows the prices for the Algonquin Citygate, Dracut, and Transcontinental Gas Pipeline (Williams Companies) (Transco) Zone 6 New York hubs to illustrate prices in the Northeast compared to Henry Hub. As expected, prices in the Northeast experience elevated prices in winter due to high seasonal demand and pipeline constraints in the region, even during normal winter weather conditions.

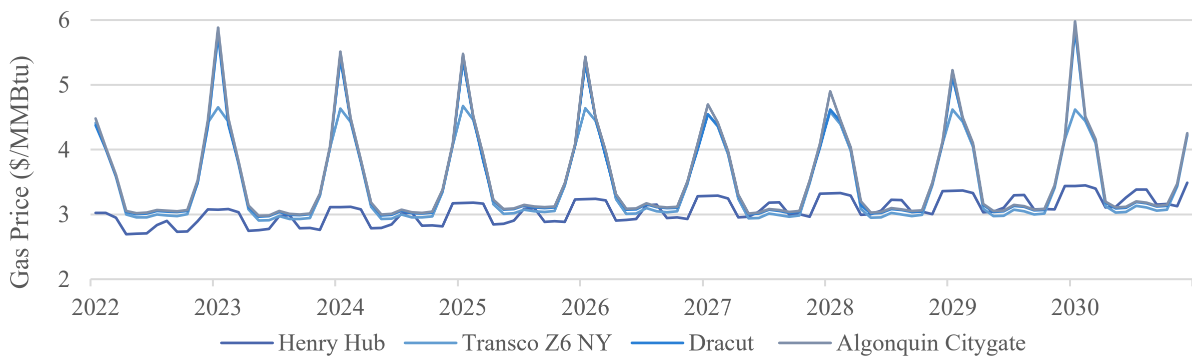


Figure 3-88. Northeast Hub Prices

4. The results showed that as pipeline utilization approached 100 percent, the price to flow through the pipeline increased and the basis differential across the link expanded. The flow along Transcontinental pipeline into New York City illustrates the relationship. **Figure 3-89** shows the seasonal rise in winter utilization along with the increase in prices.

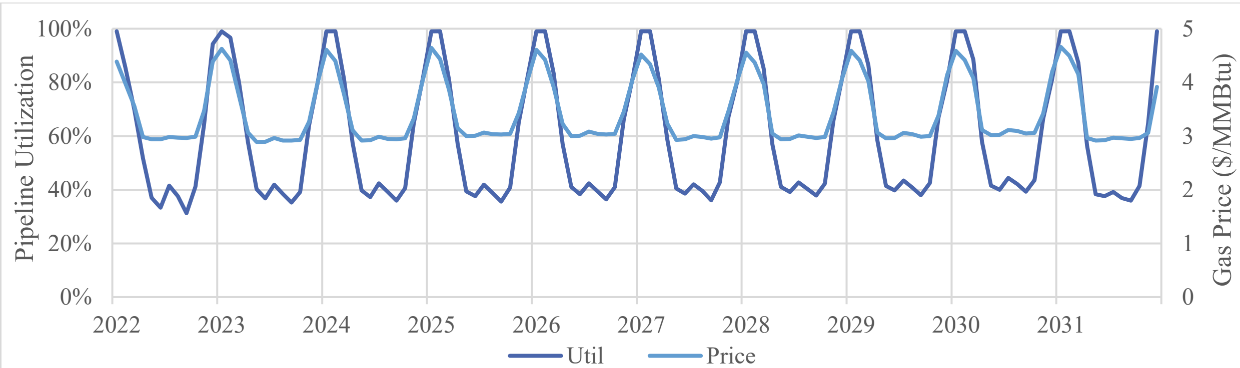


Figure 3-89. Transco Pipeline Zone 6 New York Utilization and Pricing

5. Results showed that prices in the Mid-Atlantic are not as high as in the Northeast, in part because of greater pipeline infrastructure capacity and also due to proximity to the large production areas of the Marcellus and Utica shale basins. **Figure 3-90** shows the prices for Columbia Gas Transmission (TCO) Pool, Texas Eastern Transmission Company (Tetco) M3, and Transco Zone 6 Non-New York hubs. Henry Hub is included for comparison. With TCO Pool in the Marcellus shale producing region, prices are lower at that hub than Henry Hub. Hubs such as Tetco M3 and Transco Z6 Non-NY are closer to the demand centers along the East Coast and price above Henry Hub during the high demand winter season but are below Henry Hub during the relatively lower summer periods. The higher winter prices in the Mid-Atlantic are still not as high as the winter prices in the Northeast hubs.

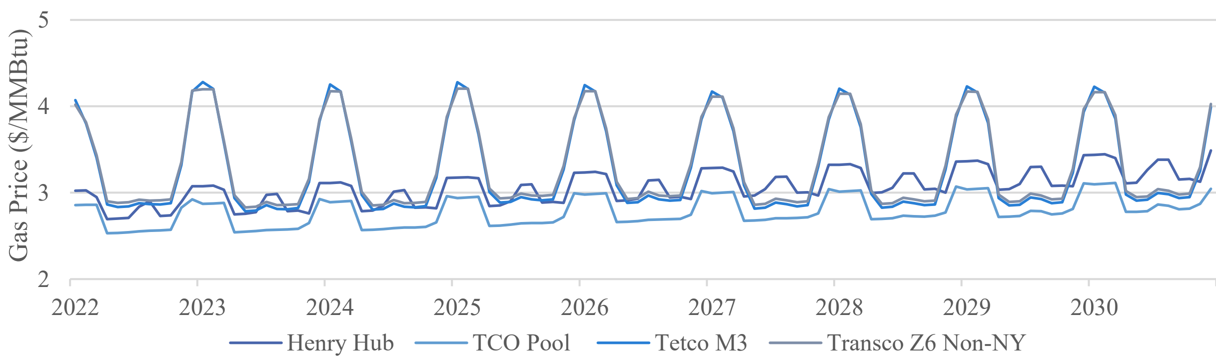


Figure 3-90. Mid-Atlantic Hub Prices

6. **Figure 3-91** shows the prices for Waha, Opal, Southern California Gas Company (SoCal Gas) Citygate, and PG&E Citygate, to illustrate prices in the West compared to the Henry Hub. Not surprisingly, prices at Waha and Opal are lower than Henry Hub given the proximity to production areas. The discount at Opal to Henry Hub declines over time as production drifts to the Permian Basin and other areas over time. The demand hubs in California price at a premium to Henry Hub. Prices in both southern and northern California start with a strong winter price seasonality but starting in 2025, northern California exhibits a summer pricing peak, though at a lower level than the winter peak. This summer peak results from the retirement of the Diablo Canyon nuclear plant in northern California and the increased power sector gas demand to replace much of the lost output of the two nuclear units. Southern California gas prices also exhibit increased summer pricing, but to a lesser extent than northern California.

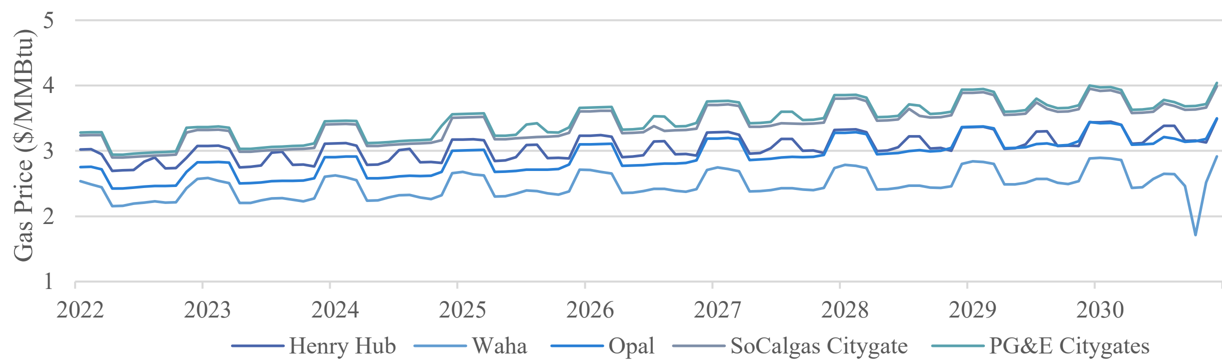


Figure 3-91. West Hub Prices

3.4.2.1 Task 3.3: Project topology of future natural gas pipeline network

Planned pipeline capacity expansions are generally defined as pipelines either under construction, approved by FERC, or those deemed likely to move forward [59]. In this analysis, future changes to the natural gas pipeline infrastructure changes were drawn from FERC; EIA's pipeline project dataset; Pipeline & Gas Journal's construction projects dataset; discussions with Interstate Natural Gas Association of America (INGAA), American Gas Association (AGA), and their members; and state permitting websites and public announcements, as shown in **Table 3-28.**

Table 3-28. Pipeline Examples

Project	Capacity	Online Year
Pecos Trail Pipeline	1.85 Bcf/d	2024
Permian Pass	2.0 Bcf/d	2024
Permian Highway	2.0 Bcf/d	2021
Double E	1.35 Bcf/d	2021
CJ Express	0.97 Bcf/d	2021
Leidy South	0.58 Bcf/d	2021
Gemini Gulf Coast	1.46 Bcf/d	2020
Hammerhead	1.56 Bcf/d	2020
Index 99	0.5 Bcf/d	2020

Consideration of future pipelines allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline capacity expansion requirements.

Coordination among the four major models (PROMOD, MarketBuilder, PSSE, NGfast) is necessary to set up the national gas-electric base case and establish a robust process for modeling each of the disruption scenarios. A basic requirement of the NTRR gas analysis is that it produce model results from the two gas models (MarketBuilder, NGfast) that are internally consistent within a variance of 5% or lower. This requirement was accomplished through validation of the results from the two models.

Validation of the preliminary MarketBuilder results was performed in multiple ways. The NGfast tool applies a general mass balance equation to Total Disposition (net storage changes plus extraction loss plus consumption) and Total Supply (marketed production plus net interstate movements plus net movements across U.S. borders plus supplemental gas supplies). In general, Supply and Disposition should balance at the state-level.

MarketBuilder results were validated at each monthly period and state, to ensure consistency in values. **Figure 3-92** shows example results for Florida; it can be seen that the percent deviation between Supply and Disposition is less than 0.2% for Florida during 2021. Similar results were calculated for other states and time periods, validating the preliminary MarketBuilder results.

Type	Source Country	Dest Country	Source State	Dest State	Source Region	Dest Region	Source Activity	Dest Activity	4/1/2021	5/1/2021	6/1/2021	7/1/2021
Production	United States	United States	Florida	Florida	Florida	Florida	Field: Florida	Hub: Florida Wholesale	0.02	0.02	0.02	0.02
Core	United States	United States	Florida	Florida	Florida	Florida	Hub: Florida Citygate	Demand: Florida Core	0.21	0.14	0.10	0.09
Industrial	United States	United States	Florida	Florida	Florida	Florida	Hub: Florida Citygate	Demand: Florida Industrial	0.27	0.26	0.27	0.26
Power	United States	United States	Florida	Florida	Florida	Florida	Hub: Florida Citygate	Demand: Florida Power	3.15	3.42	3.69	4.06
Flow	United States	United States	Alabama	Florida	Alabama	Florida	Pipe: FGT Gulf South Mobile-Florida	Hub: Florida Wholesale	1.26	1.45	1.76	2.22
Flow	United States	United States	Mississippi	Florida	Mississippi	Florida	Pipe: GulfStream	Hub: Florida Wholesale	1.24	1.29	1.29	1.29
Flow	United States	United States	Georgia US	Florida	Georgia	Florida	Pipe: Sabal Trail to North Florida	Hub: North Florida	0.90	0.90	0.90	0.90
Flow	United States	United States	Georgia US	Florida	Georgia	Florida	Pipe: South Georgia Natural Gas	Hub: North Florida	0.58	0.53	0.46	0.35
Flow	United States	United States	Florida	Georgia US	Florida	Georgia	Upload: Cypress Northbound	Hub: Elba Island Georgia	0.37	0.37	0.37	0.37
Flow	United States	United States	Florida	Georgia US	Florida	Georgia	Upload: South Georgia Natural Gas Northbound	Hub: SNG Georgia Interconnect	0.00	0.00	0.00	0.00
								Supply	4.00	4.20	4.43	4.79
								Disposition	4.00	4.19	4.43	4.78
								Percent Deviation	0.14%	0.13%	0.13%	0.12%

Figure 3-92. Comparison of MarketBuilder Results for Supply and Disposition in Florida

A second validation method examined the annual-averaged 2021 pipeline flows predicted by MarketBuilder which were found to be in general agreement with annual-averaged pipeline flows predicted by NGfast for 2020 (partial sample in **Table 3-29**) indicating that a similar temporal and spatial starting point for the two gas models.

Table 3-29. Annual-Averaged Pipeline Flows Predicted by NGfast for 2020

MB_ID	MD_acronym	Pipeline	Segment	State From	State to	MB_2021	Ngfast_2020
227	Algonquin	Algonquin Gas Trans Co	M1	New Jersey	New York	688	636
239	Algonquin	Algonquin Gas Trans Co	M2	New York	Connecticut	1,089	1,336
100	Algonquin	Algonquin Gas Trans Co	M3	Connecticut	Rhode Island	217	598
100	Algonquin	Algonquin Gas Trans Co	M4	Rhode Island	Massachusetts	217	456
190	Algonquin	Algonquin Gas Trans Co	M4 Back	Massachusetts	Rhode Island	0	0
190	Algonquin	Algonquin Gas Trans Co	M3 Back	Rhode Island	Connecticut	0	0
101	Algonquin	Algonquin Gas Trans Co	M2 Back	Connecticut	New York	0	0
238	Algonquin	Algonquin Gas Trans Co	M1 Back	New York	New Jersey	0	0

The third validation method investigated the maximum monthly-average daily gas pipeline flows predicted by MarketBuilder from 2022 to 2031 (column "Max MMcf/d") which were compared with pipeline capacity data in NGfast (column "Cap_2020") to determine possible gas flow bottlenecks which could lead to minor corrections to the NGfast tool (partial sample in

Table 3-30). The two gas models agreed in general when considering planned pipeline capacity expansions.

Table 3-30. Maximum Monthly-Average Daily Gas Pipeline Flows Predicted by MarketBuilder from 2022 to 2031 Compared with 2020 Pipeline Capacities

MB_ID	MD_acronym	Pipeline	Segment	State From	State to	Max MMcf/d	Cap_2020
227	Algonquin	Algonquin Gas Trans Co	M1	New Jersey	New York	1,070	1,532
239	Algonquin	Algonquin Gas Trans Co	M2	New York	Connecticut	1,837	1,737
100	Algonquin	Algonquin Gas Trans Co	M3	Connecticut	Rhode Island	631	1,412
100	Algonquin	Algonquin Gas Trans Co	M4	Rhode Island	Massachusetts	631	1,087
190	Algonquin	Algonquin Gas Trans Co	M4 Back	Massachusetts	Rhode Island	0	275
190	Algonquin	Algonquin Gas Trans Co	M3 Back	Rhode Island	Connecticut	0	275
101	Algonquin	Algonquin Gas Trans Co	M2 Back	Connecticut	New York	0	275
238	Algonquin	Algonquin Gas Trans Co	M1 Back	New York	New Jersey	0	275

NGfast is an impact analysis tool for natural gas systems specially designed to assess the effects of gas supply disruptions on the electric grid and downstream gas markets. The tool quantitatively describes pre-event and post-event system conditions for a given U.S. state and month of a specified year. It contains datasets that include almost all known natural gas assets in the U.S. including state border points, pipelines, local distribution companies (LDCs), underground gas storage (UGS) facilities, liquefied natural gas (LNG) facilities, and compressor stations for years 2014 to 2019 (year 2020 data is being collected).

The NGfast tool is supported by a comprehensive set of data files that are organized in a certain schema so that the structure, connectivity, and flow interactions among the various components of the gas system are sufficiently described. **Figure 3-93** shows how the individual datasets are applied to simulate the consequences of a gas pipeline break to determine gas-fired electric generators at-risk of losing gas supply [60].

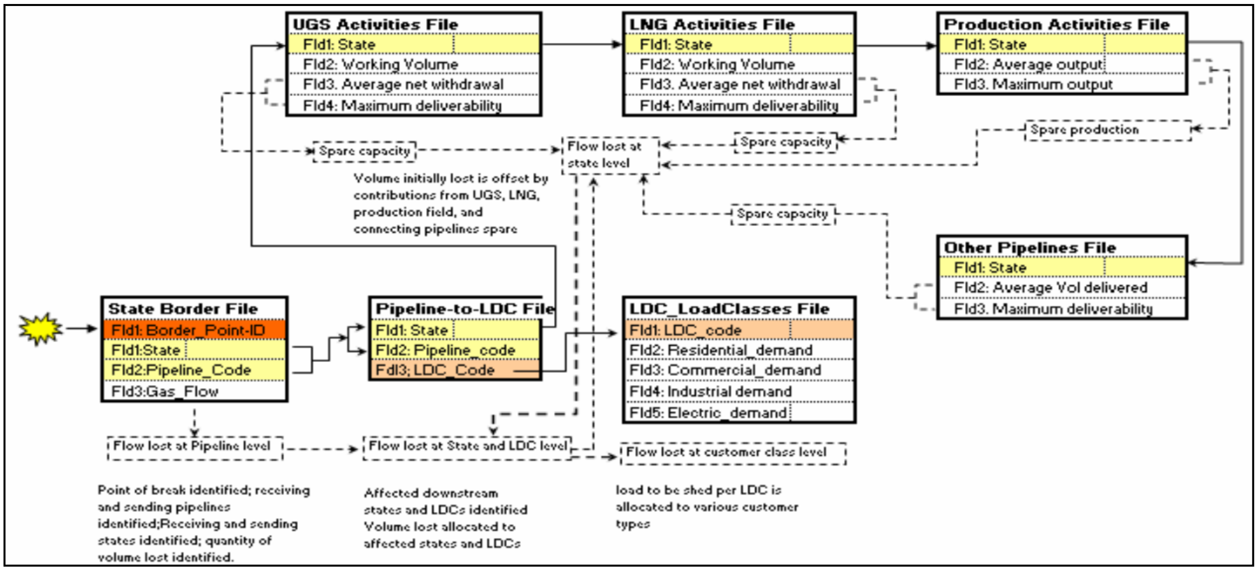


Figure 3-93. Relational Database Operation for a Pipeline Break Simulation in NGfast

As shown in **Figure 3-93**, one input into the NGfast tool is monthly demand data by State, LDC, and customer class (residential, commercial, industrial, and electric power), which were predicted based on the most-recent MarketBuilder demand numbers. The MarketBuilder demand values are generally provided at the state-level, but sub-State data is available for California, Nevada, Ohio, Pennsylvania, Texas, and West Virginia. Natural gas LDCs were identified associated with sub-state regions used in MarketBuilder for these states. LDC service territory data available from Homeland Infrastructure Foundation-Level Data (HIFLD)-Open was leveraged to identify counties served by LDCs within each sub-state region. Sub-state regions in MarketBuilder were then associated with interstate pipelines to determine possible supply points for the LDCs in each sub-state region. **Figure 3-94** provides example information on sub-state demand data for the four Ohio regions (northeast [NE], northwest [NW], southeast [SE], and southwest [SW]) in the upper left corner, with the lower left corner identifying LDCs in Ohio and their service areas depicted in the map shown on the right side. The information in **Figure 3-94** was used to downscale the sub-state demand data to customer class demands for LDCs in Ohio.

Dest Activity	Apr-21	May-21	Jun-21
Demand: NE OH Core	3.81E-01	2.48E-01	1.82E-01
Demand: NW OH Core	1.07E-01	7.00E-02	5.12E-02
Demand: SE OH Core	2.23E-01	1.46E-01	1.05E-01
Demand: SW OH Core	2.46E-01	1.61E-01	1.18E-01

Year	State	Company Name	Core Demand (Mcf)
2020	OH	COLUMBIA GAS OF OHIO	169,531,218
2020	OH	OHIO GAS COMPANY	5,454,702
2020	OH	NORTHEAST OHIO NATURAL GAS	4,285,470
2020	OH	NATIONAL GAS AND OIL COOPERATIVE	2,838,090
2020	OH	SUBURBAN NATURAL GAS COMPANY	1,862,938
2020	OH	KNOX ENERGY COOPERATIVE ASSOCIATION	1,696,504
2020	OH	LANCASTER MUNICIPAL GAS	1,279,413
2020	OH	CONSUMERS GAS COOP	1,041,019

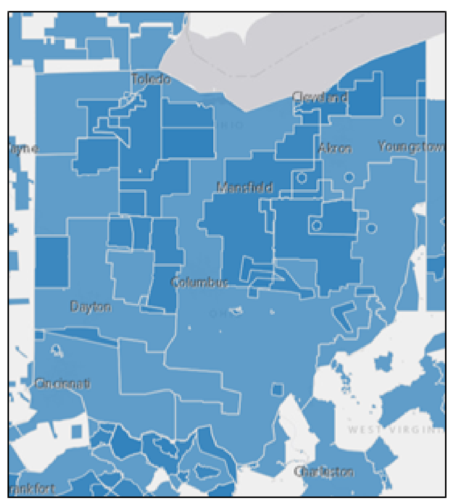


Figure 3-94. Information on MarketBuilder Sub-State Regions in Ohio Together with LDC Demand Data

The monthly demand values were estimated using EIA annual data for 2020 [61] and matching the individual LDCs with the MarketBuilder region and State values and determining the ratio of State/region demands with LDC customer values (see **Figure 3-95**).

State	Company	Item	Ratio	Dest Activity	4/1/2021	5/1/2021	6/1/2021	7/1/2021
Alabama	ALABAMA GAS CORP	Commercial Volume	2.30E-01	Demand: Alabama Core	0.028	0.018	0.013	0.012
Alabama	ALABAMA GAS CORP	Electric Power Volume	4.69E-02	Demand: Alabama Power	0.033	0.044	0.052	0.059
Alabama	ALABAMA GAS CORP	Industrial Volume	2.33E-01	Demand: Alabama Industrial	0.127	0.122	0.120	0.116
Alabama	ALABAMA GAS CORP	Residential Volume	3.14E-01	Demand: Alabama Core	0.038	0.025	0.018	0.017
Alabama	ALABAMA GAS CORP	Vehicle Fuel Volume	8.32E-05	Demand: Alabama Core	0.000	0.000	0.000	0.000
Alabama	ALEXANDER CITY MUN GAS CO	Commercial Volume	2.73E-03	Demand: Alabama Core	0.000	0.000	0.000	0.000
Alabama	ALEXANDER CITY MUN GAS CO	Residential Volume	1.62E-03	Demand: Alabama Core	0.000	0.000	0.000	0.000
Alabama	AMERICAN MIDSTREAM ALA INTRASTATE	Industrial Volume	1.76E-02	Demand: Alabama Industrial	0.010	0.009	0.009	0.009
Alabama	AMERICAN MIDSTREAM BAMAGAS LLC	Electric Power Volume	7.49E-02	Demand: Alabama Power	0.053	0.071	0.083	0.094
Alabama	AMERICAN MIDSTREAM TENNESSEE RIVER	Industrial Volume	2.74E-02	Demand: Alabama Industrial	0.015	0.014	0.014	0.014
Alabama	ATHENS GAS DEPT CITY OF	Commercial Volume	7.82E-03	Demand: Alabama Core	0.001	0.001	0.000	0.000
Alabama	ATHENS GAS DEPT CITY OF	Industrial Volume	3.36E-03	Demand: Alabama Industrial	0.002	0.002	0.002	0.002
Alabama	ATHENS GAS DEPT CITY OF	Residential Volume	5.26E-03	Demand: Alabama Core	0.001	0.000	0.000	0.000
Alabama	ATHENS GAS DEPT CITY OF	Vehicle Fuel Volume	2.97E-05	Demand: Alabama Core	0.000	0.000	0.000	0.000

Figure 3-95. Example Estimated Customer Class Data as a Function of Month and LDC

Monthly results were estimated for over 1,600 LDCs in the U.S. for the months of April 2021 to March 2031. It was noted that the current MarketBuilder results did not include data for Washington Gas Light in the District of Columbia. This analysis assumed that the split of Washington Gas Light's operations in Maryland and Virginia compared to the District of Columbia would remain a constant value of 40% in future years.

Table 3-31. Ratio of Natural Gas Deliveries in the District of Columbia Compared to Maryland, for Washington Gas Light Company

Area	Company	Item	2017	2018	2019	2020
District of Columbia	WASHINGTON GAS LIGHT COMPANY	Core	28,325,173	30,159,739	28,635,971	26,528,567
Maryland	WASHINGTON GAS LIGHT COMPANY	Core	67,984,251	73,608,658	71,268,744	66,881,166
Maryland	WASHINGTON GAS LIGHT COMPANY	Power	9,608,505	16,725,666	6,483,345	7,021,092
Virginia	WASHINGTON GAS LIGHT COMPANY	Core	62,971,426	70,769,320	65,854,198	62,015,670
---	**Ratio DC-Core to MD-Core**	---	**42%**	**41%**	**40%**	**40%**

The evolution of the electric sector in the national electric-gas base case is determined by the PROMOD software, which is a fundamental electric market simulation solution that incorporates a generator and portfolio modeling system. PROMOD provides information on individual electric generators which were compared with public EIA data on gas-fired electric generators (partial sample in **Figure 3-96**). Fuzzy logic search techniques were used to link gas-fired generator names in PROMOD (column "UnitDescription") with EIA generator names (column "Plant Name"). The Gas Team verified the fuzzy logic results and researched gas-fired generators for which no match was found, to establish the appropriate connection between the PROMOD results and EIA power plant data.

UnitDescription	UnitNum	UnitCategory	Area	Plant Name	Plant Code	Generator ID	Utility ID	Utility Name	State	Technology	Prime Mover	Nameplate Capacity (MW)	Similarity
Allegheny Energy Units 3 4 & 5:CC	1	Combined Cycle	PJM	Allegheny Energy Units 3 4 & 5	55710	UNT3	61267	Springdale Energy LLC	PA	Natural Gas Fired Combined Cycle	CT	184.0	0.9682
Bear Garden Generating Station:CC 2	1	Combined Cycle	PJM	Bear Garden	56807	1A	19876	Virginia Electric & Power Co	VA	Natural Gas Fired Combined Cycle	CT	145.0	0.8875
Bergen:CC1	1	Combined Cycle	PJM	Bergen Generating Station	2398	1501	15147	PSEG Fossil LLC	NJ	Natural Gas Fired Combined Cycle	CA	325.2	
Bergen:CC2	2	Combined Cycle	PJM	Bergen Generating Station	2398	2301	15147	PSEG Fossil LLC	NJ	Natural Gas Fired Combined Cycle	CA	258.4	
Bethlehem Power Plant:CC1	1	Combined Cycle	PJM	Bethlehem Power Plant	55690	CTG1	56607	Calpine Bethlehem LLC	PA	Natural Gas Fired Combined Cycle	CT	127.0	0.9412
Bethlehem Power Plant:CC2	5	Combined Cycle	PJM	Bethlehem Power Plant	55690	CTG1	56607	Calpine Bethlehem LLC	PA	Natural Gas Fired Combined Cycle	CT	127.0	0.9412
Birdsboro Power:CC1	1	Combined Cycle	PJM	Birdsboro Power	61035	GEN1	60672	Birdsboro Power LLC	PA	Natural Gas Fired Combined Cycle	CS	525.0	0.9412
Brunot Island:CC	1	Combined Cycle	PJM	Brunot Island	3096	2A	63032	Brunot Island Power, LLC	PA	Natural Gas Fired Combined Cycle	CT	65.3	0.9333
Brunswick County Power Station:CC	1	Combined Cycle	PJM	Brunswick County Power Station	58260	CT01	19876	Virginia Electric & Power Co	VA	Natural Gas Fired Combined Cycle	CT	297.5	0.9333
Camden Cogeneration:CC	1	Combined Cycle	PJM	Camden Plant Holdings LLC	10751	GEN2	63360	Camden Plant Holdings LLC	NJ	Natural Gas Fired Combined Cycle	CA	77.7	
Capitol Power Plant:CC1	1	Combined Cycle	PJM	AOC, Capitol Power Plant	63347	CTG1	63113	Architect of the Capitol, Capitol Power Plant	DC	Natural Gas Fired Combustion Turbine	GT	7.5	0.6741
Carroll County Energy Project:CC1	1	Combined Cycle	PJM	Carroll County Energy	59773	CGT1	59541	Carroll County Energy LLC	OH	Natural Gas Fired Combined Cycle	CT	235.5	0.9182
Center Port Terminal:CC	1	Combined Cycle	PJM										
Chesterfield:CC7	1	Combined Cycle	PJM	Chesterfield	3797	CW7	19876	Virginia Electric & Power Co	VA	Natural Gas Fired Combined Cycle	CA	74.4	0.9000
Chesterfield:CC8	2	Combined Cycle	PJM	Chesterfield	3797	CW8	19876	Virginia Electric & Power Co	VA	Natural Gas Fired Combined Cycle	CA	79.2	0.9000
Cordova Energy Center:CC	1	Combined Cycle	PJM	Cordova Energy	55188	PT11	4210	Cordova Energy Co LLC	IL	Natural Gas Fired Combined Cycle	CT	210.0	0.9000
CPV Fairview:CC1	1	Combined Cycle	PJM	CPV Fairview Energy Center	60589	GEN1	60350	CPV Fairview, LLC	PA	Natural Gas Fired Combined Cycle	CT	372.0	0.7200
CPV St Charles:CC	1	Combined Cycle	PJM	CPV St Charles Energy Center	56846	GTG1	56031	CPV Maryland LLC	MD	Natural Gas Fired Combined Cycle	CT	215.0	0.7354
CPV Woodbridge Energy Center:CC1	1	Combined Cycle	PJM	Woodbridge Energy Center	57839	CT001	57166	Woodbridge Energy Center	NJ	Natural Gas Fired Combined Cycle	CT	222.7	0.9040
Doswell Combined Cycle Facility:CC1	1	Combined Cycle	PJM	McIntosh Combined Cycle Facility	56150	10ST	7140	Georgia Power Co	GA	Natural Gas Fired Combined Cycle	CA	281.9	0.6312
Doswell Combined Cycle Facility:CC2	2	Combined Cycle	PJM	McIntosh Combined Cycle Facility	56150	10ST	7140	Georgia Power Co	GA	Natural Gas Fired Combined Cycle	CA	281.9	0.6312
Dover Energy (NRG):CC1	1	Combined Cycle	PJM	Energy Center Dover	10030	COG1	7860	Energy Center Dover LLC	DE	Natural Gas Fired Combined Cycle	CA	18.6	0.8700
Dresden Energy Facility:CC	1	Combined Cycle	PJM	Dresden Energy Facility	55350	1	733	Appalachian Power Co	OH	Natural Gas Fired Combined Cycle	CT	198.9	0.9300
Eagle Point Cogeneration:CC	1	Combined Cycle	PJM	Eagle Point Power Generation	50561	GTG1	49942	Eagle Point Power Generation LLC	NJ	Natural Gas Fired Combined Cycle	CT	90.0	0.7570
Elmwood Park:CC	1	Combined Cycle	PJM	Elmwood Park Power LLC	50852	GEN2	63363	Elmwood Park Power LLC	NJ	Natural Gas Fired Combined Cycle	CA	22.9	
Fairless Energy Center:CC1	1	Combined Cycle	PJM	Fairless Energy Center	55298	CT1A	61786	Edgewater Generation, LLC	PA	Natural Gas Fired Combined Cycle	CT	198.9	0.9412
Fairless Energy Center:CC2	3	Combined Cycle	PJM	Fairless Energy Center	55298	CT1A	61786	Edgewater Generation, LLC	PA	Natural Gas Fired Combined Cycle	CT	198.9	0.9412
Fayette Energy Facility:CC1	1	Combined Cycle	PJM	Fayette Energy Facility	55516	CTG1	59923	Dynegy Fayette Energy Facility	PA	Natural Gas Fired Combined Cycle	CT	163.5	0.9412
Federal Research Center White Oak:CC1	1	Combined Cycle	PJM	Central Utility Plant at White Oak	58207	G12	58178	GSA Metropolitan Service Center	MD	Natural Gas Fired Combined Cycle	CA	5.0	
Fremont Energy Center:CC	1	Combined Cycle	PJM	Fremont Energy Center	55701	CA01	40577	American Mun Power-Ohio, Inc	OH	Natural Gas Fired Combined Cycle	CA	358.7	0.9300
Garrison Energy Center:CC1	1	Combined Cycle	PJM	Garrison Energy Center LLC	57349	CTG1	56691	Garrison Energy Center LLC	DE	Natural Gas Fired Combined Cycle	CT	235.0	0.7738
Goddard Steam Plant:CC1	1	Combined Cycle	PJM										

Figure 3-96. Linking PROMOD Gas-Fired Generators with EIA Power Plant Data

An analysis of all gas contracting positions in current gas-fired electric generators was undertaken to further refine the inputs to the modeling setup, as this plays a key role in how plants are supplied, and which power plants are ultimately affected during gas shortages and/or curtailments. EIA Form 860 and 923 data was collected for all current gas-fired electric generators (partial sample in **Figure 3-97**) and combined to determine what type of contracts are maintained for gas supply for each gas-fired electric generator (column titled "Natural Gas Supply Contract Type"), delivery contracts (column titled "Natural Gas Delivery Contract Type"), and whether these contracts are either Firm ("F") or Interruptible ("I").

Plant Name	Plant Code	Utility ID	Utility Name	State	Percent Utilized (2020)	Natural Gas Supply Contract Type	Natural Gas Delivery Contract Type	Natural Gas LDC Name	Natural Gas Pipeline Name 1	Natural Gas Pipeline Name 2
Barry	3	195	Alabama Power Co	AL	65.3%	F	F		BAY GAS STORAGE	
Greene County	10	195	Alabama Power Co	AL	9.5%	F	F	ALABAMA GAS CORP		
Madelia	30	29305	City of Madelia - (MN)	MN	0.0%	no data	no data	CENTERPOINT ENERGY		
J K Smith	54	5580	East Kentucky Power Coop, Inc	KY	3.4%	F	I		TENNESSEE GAS PIPELINE COMPANY	TEXAS EASTERN TRANSMISSION LP
Frederickson	99	15500	Puget Sound Energy Inc	WA	0.0%	F	F		NORTHWEST PIPELINE GP	
Ocotillo	116	803	Arizona Public Service Co	AZ	9.2%	F	F		EL PASO NATURAL GAS COMPANY LLC	
West Phoenix	117	803	Arizona Public Service Co	AZ	34.1%	F	F		EL PASO NATURAL GAS COMPANY LLC	
Yucca	120	803	Arizona Public Service Co	AZ	14.4%	F	F		EL PASO NATURAL GAS COMPANY LLC	
H Wilson Sundt Generating Station	126	24211	Tucson Electric Power Co	AZ	38.4%	F	F		EL PASO NATURAL GAS COMPANY LLC	
Agua Fria	141	16572	Salt River Project	AZ	6.4%	F	F		EL PASO NATURAL GAS COMPANY LLC	
Kyrene	147	16572	Salt River Project	AZ	33.0%	F	F		EL PASO NATURAL GAS COMPANY LLC	
Apache Station	160	796	Arizona Electric Pwr Coop Inc	AZ	42.6%	F	F		EL PASO NATURAL GAS COMPANY LLC	
Thomas Fitzhugh	201	807	Arkansas Electric Coop Corp	AR	0.0%	I	I		OZARK GAS TRANSMISSION LLC	
Humboldt Bay	246	14328	Pacific Gas & Electric Co.	CA	32.9%	F	F	PACIFIC GAS		
Dynegy Moss Landing Power Plant Hybrid	260	54802	Dynegy -Moss Landing LLC	CA	42.6%	F	F	PACIFIC GAS		
AES Alamitos LLC	315	22148	AES Alamitos LLC	CA	5.6%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
AES Huntington Beach LLC	335	23693	AES Huntington Beach LLC	CA	5.6%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
Ormond Beach	350	15908	GenOn California South, LP	CA	5.1%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
AES Redondo Beach LLC	356	22484	AES Redondo Beach LLC	CA	4.3%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
Mountainview Generating Station	358	17609	Southern California Edison Co	CA	31.6%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
Grayson	377	7294	City of Glendale - (CA)	CA	4.8%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
El Centro Hybrid	389	9216	Imperial Irrigation District	CA	20.3%	F	F	SOUTHERN CALIFORNIA GAS COMPANY		
Harbor	399	11208	Los Angeles Department of Water & Power	CA	1.2%	I	I	SOUTHERN CALIFORNIA GAS COMPANY		
Haynes	400	11208	Los Angeles Department of Water & Power	CA	24.2%	I	I	SOUTHERN CALIFORNIA GAS COMPANY		
Scattergood	404	11208	Los Angeles Department of Water & Power	CA	22.2%	I	I	SOUTHERN CALIFORNIA GAS COMPANY		
Valley (CA)	408	11208	Los Angeles Department of Water & Power	CA	13.9%	I	I	SOUTHERN CALIFORNIA GAS COMPANY		

Figure 3-97. Gas Contracts and Pipeline Connections for Gas-Fired Electric Generators

Although contractual behavior varies from utility to utility, this analysis indicates that a common contracting approach is to contract enough Firm delivery capacity to cover baseload needs and flex on Interruptible delivery capacity for peaking generation.

Natural gas contracts determine the order of load shedding in the event of loss of gas supply with Interruptible customers load typically shed first (see **Figure 3-98**). To confirm the curtailment policy of gas-fired generators during extreme weather, EIA Form 923 data for February 2021 was collected and examined. This data indicated gas-fired generators with firm supply and delivery contracts were able to operate during the 2021 Texas Polar Vortex, with very limited gas supply to non-firm gas-fired generators (<20% of total).

- **Order of load shedding (curtailment) for natural gas local distribution companies:**
  - ✓ Interruptible customers
  - ✓ Non-forecasted dispatchable generation
  - ✓ Dispatched electric generation
  - ✓ Non-electric non-core customers
  - ✓ All non-core (e.g., petroleum refineries)
  - ✓ Large commercial and industrial core customers
  - ✓ Small commercial and industrial customers
  - ✓ All residential customers

Figure 3-98. Order of Curtailment of LDC Customers

This contracting analysis was also instrumental in updating the proprietary dataset used in NGfast in modelling disruption impacts to gas-fired power plants and formed a critical part of in the combined electric-gas modeling analysis by allowing for a more accurate simulation of curtailment procedures of firm versus interruptible gas supply.

Upon completion of the national electric and gas base case, pipeline/LDC-to-power plant connections and initial assignment of gas supply and delivery contract types for proposed future gas-fired generators were determined (based on EIA Form 860 data).

A list of future gas-fired generators was developed using data from S&P Capital IQ containing a total of 184 power plants – 25 in Canada and 4 in Mexico (see **Figure 3-99**). The status of future power plants was provided by NERC Tier. The S&P data expands on a list that can be generated using EIA data via its 2020 Form 860 [62] and is therefore more inclusive.

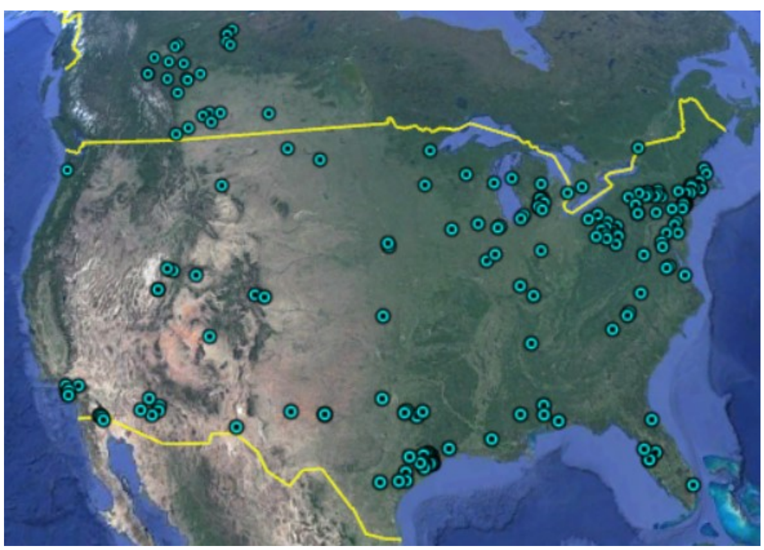


Figure 3-99. Locations of Future Gas-Fired Generators

Connections of the future gas-fired generators to the gas infrastructure was based on current gas network, considering proximity to gas transmission pipeline(s) and comparison with gas connections with currently operating power plants. Power plants with large nameplate capacities were assumed to be supplied by transmission pipeline(s) with LDC connections assumed for smaller (up to 100 MW) gas-fired generators (as appropriate). **Figure 3-100** shows a partial sample of assumed gas connections for future gas-fired generators. A complete internal review of natural gas connections was performed using proprietary DOT National Pipeline Mapping System (NPMS) data.

Latitude	Longitude	Power Plant	Interconnected Utility Compar	State	County	Nameplate Capacity (M	Development Status	Build Phase Online `	Natural Gas LDC Name	Natural Gas Pipeline Name 1	Natural (
32.9478	-112.716	Gila Bend		AZ	Maricopa	460	Early Development	2025		EL PASO NATURAL GAS COMPANY LLC	TRANS
32.91669	-111.50359	Coolidge Generating Station	Salt River Project Agricultural	AZ	Pinal	699	Early Development	NA		TRANSWESTERN PIPELINE COMPANY	EL PAS
33.155	-111.48361	Copper Crossing Gen Station (Abel Peaking)	Salt River Project Agricultural	AZ	Pinal	400	Postponed	NA		TRANSWESTERN PIPELINE COMPANY	EL PAS
32.6883	-111.92011	Desert Basin Generating CT	Arizona Public Service Comp.	AZ	Pinal	7.4	Early Development	NA		TRANSWESTERN PIPELINE COMPANY	KINDER
32.40099	-115.199	Baja California IV Cerro Prieto Project	Comision Federal de Electrici	Baja Cali	0	22.7	Announced	2023		Transportadora de Gas Natural de Baja California	
32.62427	-115.45237	Baja California Vi Mexicali	CFEnergia SA de CV (CFEN)	Baja Cali	0	135	Announced	2025		Gasoducto Rosarito	
32.55949	-115.30643	Cuernavaca Power Generation Plant	Comision Federal de Electrici	Baja Cali	0	204	Announced	2022		Transportadora de Gas Natural de Baja California	
32.6326	-115.5292	González Ortega Combined Cycle Project	Comision Federal de Electrici	Baja Cali	0	900	Announced	2023		Transportadora de Gas Natural de Baja California	
33.76907	-118.1016	Alamitos Repowering CT	Southern California Edison C	CA	Los Angele	900	Early Development	2022	SOUTHERN CALIFORNIA GAS COMPANY		
33.90704	-118.01307	Biola University	Southern California Edison C	CA	Los Angele	255	Construction Begun	2021	SOUTHERN CALIFORNIA GAS COMPANY		
34.15548	-118.27816	Grayson IC Plant	Glendale City of	CA	Los Angele	60	Announced	2021	SOUTHERN CALIFORNIA GAS COMPANY		
33.64449	-117.97951	Huntington Beach Repowering CT	Southern California Edison C	CA	Orange	1,800.00	Early Development	2024	SOUTHERN CALIFORNIA GAS COMPANY		
34.17315	-117.34702	OES Biogas Power (San Bernardino Waste-to-Ener	Southern California Edison C	CA	San Bernar	750	Construction Begun	2021	SOUTHERN CALIFORNIA GAS COMPANY		
38.82484	-104.83253	Colorado Springs Gas Project	Colorado Springs Utilities	CO	El Paso	140	Early Development	2022		COLORADO SPRINGS UTILITIES	
38.99358	-105.50777	Coyote Clean Power Project		CO	La Plata	93	Early Development	2025	GREELEY GAS CO		
41.3778	-73.45864	Danbury Fuel Cell Project		CT	Fairfield	2.8	Announced	NA	YANKEE GAS SVC CO	ALGONQUIN GAS TRANSMISSION COM	ALGON
41.78353	-72.70331	CT RFP-1 Fuel Cell (Hartford Fuel Cell)		CT	Hartford	2.6	Early Development	2021	CONNECTICUT NAT GAS CORP		
41.78339	-72.70325	Homestead Fuel Cell Project		CT	Hartford	195	Announced	2022	CONNECTICUT NAT GAS CORP		
41.66548	-72.77096	New Britain Fuel Cell Project		CT	Hartford	22	Announced	NA	CONNECTICUT NAT GAS CORP		
41.55449	-72.58005	Middletown Repowering Project	The Connecticut Light and Pc	CT	Middlesex	17.9	Early Development	NA		ALGONQUIN GAS TRANSMISSION COMPANY	
41.32468	-73.09879	Derby Fuel Cell (Fuel Cell Energy)		CT	New Haven	14	Early Development	2022	YANKEE GAS SVC CO		
41.33546	-73.09652	Derby Fuel Cell Project		CT	New Haven	2.8	Early Development	NA	YANKEE GAS SVC CO		
41.4002	-72.08592	Naval Sub Base New London Fuel Cell (Submarine	Connecticut Municipal Electri	CT	New Londor	1,062.00	Construction Begun	2021	YANKEE GAS SVC CO		
41.40013	-72.0856	Subase Microgrid Project FC		CT	New Londor	721	Construction Begun	2021	YANKEE GAS SVC CO	ALGONQUIN GAS TRANSMISSION COMPANY	
41.86346	-71.9165	Killingly Energy Center	The Connecticut Light and Pc	CT	Windham	150	Advanced Developm	2024	YANKEE GAS SVC CO		
38.8824	-77.007527	Capitol Power Cogeneration Plant		DC	Washingtor	186	Announced	NA	WASHINGTON GAS LIGHT COMPANY		
39.17795	-75.501899	Garrison Energy Center	Delmarva Power & Light Comp	DE	Kent	280	Early Development	2021	CHESAPEAKE UTILITIES CORPORATION		
26.06857	-80.19846	FPL Dania Beach Clean Energy Center	Florida Power & Light Compar	FL	Broward	1,250.00	Construction Begun	2022		FLORIDA GAS TRANSMISSION COMPANY	
30.56673	-87.22679	Gulf Clean Energy Center CT (Crist)	Gulf Power Company	FL	Escambia	500	Early Development	2022		GULF SOUTH PIPELINE COMPANY LP	
27.79465	-82.40385	Big Bend CC Repower Project	Tampa Electric Company	FL	Hillsboroug	126	Construction Begun	2023		FLORIDA GAS TRANSMISSION COMPAN	GULFST
27.79465	-82.40385	Big Bend CT	Tampa Electric Company	FL	Hillsboroug	44	Construction Begun	2021		FLORIDA GAS TRANSMISSION COMPAN	GULFST

Figure 3-100. Assumed Gas Connections for Future Gas-Fired Generators

A natural gas pricing hub is used as a central pricing point for a region's natural gas. Gas pricing hubs are the heart of gas infrastructure networks such as pipelines and liquefied natural gas (LNG) terminals. The current gas pricing hub network in MarketBuilder was connected to the physical pipeline infrastructure using EIA data [63] as shown in **Figure 3-101** (partial sample). Natural gas hub information is used to determine the price of natural gas at delivery points throughout the North American gas market.

State	Layer	Region Tag	hub 1	hub 2	hub 3
Alabama	Demand	Alabama	Florida Gas Zone 3	Transco Zone 4	
Alaska	Demand	Alaska	---	---	---
Arizona	Demand	Arizona Gas	El Paso S. Mainline/N. Baja	SoCal Border Avg.	
Arizona	Demand	Northern Arizona Gas	El Paso non-Bondad		
Arkansas	Demand	Arkansas	Texas Gas Zone 1	Texas Eastern, M1, 24	Enable South
California	Demand	PG&E Gas	PG&E Citygate	Malin	
California	Demand	SDG&E Gas	SoCal Citygate		
California	Demand	SoCalGas Gas	SoCal Border Avg.		
Colorado	Demand	Colorado	Northwest S. of Green River	White River Hub	
Connecticut	Demand	Connecticut	Algonquin Citygate	Iroquois Zone 2	
Delaware	Demand	Delaware	Transco Zone 6 non-NY		
Florida	Demand	Florida	FGT Citygate		
Georgia US	Demand	Georgia	Transco Zone 4	Transco Zone 5	Florida Gas Zone 3
Idaho	Demand	Idaho	Stanfield	Northwest Wyoming Pool	Kingsgate
Illinois	Demand	Illinois	Chicago Citygate		
Indiana	Demand	Indiana	Chicago Citygate	Lebanon	Michigan Consolidated
Iowa	Demand	Iowa	Northern Natural Ventura	Chicago Citygate	
Kansas	Demand	Kansas	Panhandle Eastern	NGPL Midcontinent	
Kentucky	Demand	Kentucky	Texas Gas Zone 1	Lebanon	Columbia Gas
Louisiana	Demand	Louisiana Gas	N. LA Regional Average		
Louisiana	Demand	Southwest Louisiana Gas	S. LA Regional Avg.		
Maine	Demand	Maine	Dracut		
Maryland	Demand	Maryland	Columbia Gas	Transco Zone 5	
Massachusetts	Demand	Massachusetts	Algonquin Citygate	Tenn Zone 6 200L	Dracut
Michigan	Demand	Michigan	Consumers Energy	Michigan Consolidated	ANR ML7
Minnesota	Demand	Minnesota	Northern Natural Ventura	Emerson	
Mississippi	Demand	Mississippi	Tennessee Line 500	Florida Gas Zone 3	Texas Eastern M-1, 30
Missouri	Demand	Missouri	Texas Eastern, M1, 24	Chicago Citygate	Panhandle Eastern
Montana	Demand	Montana	Empress	Stanfield	Opal
Nebraska	Demand	Nebraska	NGPL Amarillo Mainline	Cheyenne Hub	

Figure 3-101. Gas Pricing Hubs

The Market Builder network contains multiple pipeline links between individual States and each link can be comprised of multiple pipelines. The NGfast tool contains a total of nearly 1,000 State Border Points with detailed natural gas pipeline information. **Figure 3-102** shows a comparison of the state-to-state pipeline links in the Market Builder model with the state border points in NGfast.

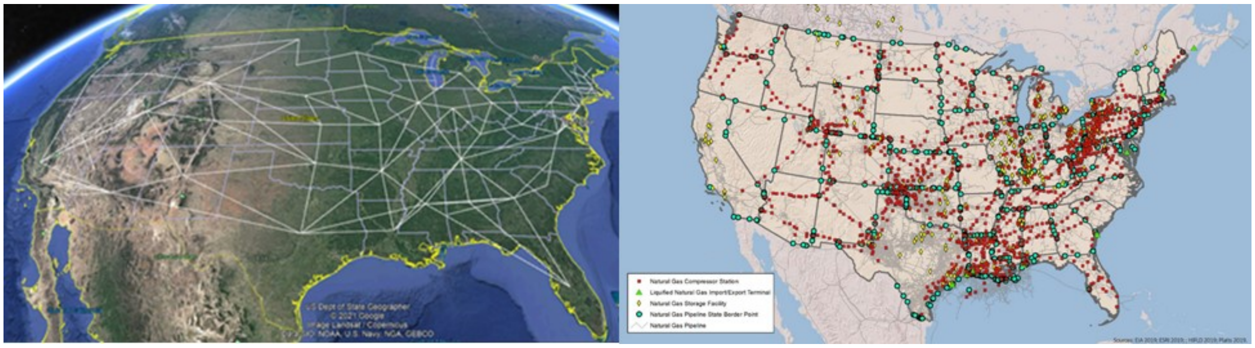


Figure 3-102. Comparison of Pipeline Links between MarketBuilder (left) and NGfast (right)

The comparison showed very good agreement between pipeline networks in Market Builder and NGfast; **Figure 3-103** shows example pipeline links for Algonquin Gas Transmission and American Natural Resources Company (ANR) Pipelines. The Gas Team was working (but did not complete) the assignment of the multiple pipeline connections between states, and also accounting for LNG liquefaction export facilities and import/ export points with Canada and Mexico when DOE notified the project team of the project termination.

MB#	MarketBuilder Cross-State Link	ye	Pipeline	Region Fro	Region To	State From	County Fro	State To	County To	Capacity (mmcfd)
35	Pipe: Algonquin Connecticut-NY	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	Connecticut	Fairfield	New York	Putnam	275
37	Hub: Connecticut and Rhode Island	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	Connecticut	Windham	Rhode Island	Providence	1,142
110	Pipe: Algonquin Mass-Connecticut RI	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	Massachusetts	Worcester	Rhode Island	Providence	275
147	Pipe: Algonquin NJ-Ramapo NY	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	New Jersey	Bergen	New York	Rockland	1,532
158	Pipe: Algonquin Ramapo NY-Connecticut	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	New York	Putnam	Connecticut	Fairfield	1,737
162	Pipe: Algonquin NY-NJ	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	New York	Rockland	New Jersey	Bergen	275
33?	Pipe: Algonquin and TGP Conn and Rhode Island to Mass	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	Rhode Island	Providence	Connecticut	Windham	275
33?	Pipe: Algonquin and TGP Conn and Rhode Island to Mass	2020	Algonquin Gas Trans Co	Northeast	Intra-regional	Rhode Island	Providence	Massachusetts	Worcester	1,087
54	Pipe: ANR Chicago-Michigan	2020	ANR Pipeline Co	Midwest	Intra-regional	Illinois	Cook	Indiana	Lake	1,384
59	Pipe: ANR Chicago-Wisconsin	2020	ANR Pipeline Co	Midwest	Intra-regional	Illinois	Mc Herny	Wisconsin	Walworth	1,841
62	Pipe: ANR IN-KY	2020	ANR Pipeline Co	Midwest	Intra-regional	Indiana	Spencer	Kentucky	Daviees	750
63	Pipe: ANR IN-OH	2020	ANR Pipeline Co	Midwest	Northeast	Indiana	Steuben	Ohio	Williams	1,748
67	Pipe: ANR Iowa Illinois	2020	ANR Pipeline Co	Midwest	Intra-regional	Iowa	Louisa	Illinois	Mercer	653
78	Pipe: ANR KY-IN	2020	ANR Pipeline Co	Midwest	Intra-regional	Kentucky	Daviees	Indiana	Spencer	1,386
83	Pipe: ANR KY-TN	2020	ANR Pipeline Co	Midwest	Intra-regional	Kentucky	Calloway	Tennessee	Henry	750
112	Pipe: ANR MI-Chicago	2020	ANR Pipeline Co	Midwest	Intra-regional	Michigan	Cass	Indiana	Elkhart	1,567
113	Pipe: ANR MI-OH	2020	ANR Pipeline Co	Midwest	Northeast	Michigan	Lawnee	Ohio	Fulton	100
114	Pipe: ANR Michigan-Wisconsin	2020	ANR Pipeline Co	Midwest	Intra-regional	Michigan	Iron	Wisconsin	Florence	860
128	Pipe: ANR MS-Monroe	2020	ANR Pipeline Co	South Central	Intra-regional	Mississippi	Washington	Arkansas	Chicot	1,150
130	Pipe: ANR MS-TN	2020	ANR Pipeline Co	South Central	Midwest	Mississippi	Marshall	Tennessee	Fayette	1,753
140	Pipe: ANR Missouri-Iowa	2020	ANR Pipeline Co	Midwest	Intra-regional	Missouri	Harrison	Iowa	Decatur	680
169	Pipe: ANR Defiance OH-IN	2020	ANR Pipeline Co	Northeast	Midwest	Ohio	Williams	Indiana	Steuben	452
175	Pipe: ANR Defiance OH-MI	2020	ANR Pipeline Co	Northeast	Midwest	Ohio	Fulton	Michigan	Lawnee	932
182	Pipe: ANR Kansas	2020	ANR Pipeline Co	South Central	Intra-regional	Oklahoma	Beaver	Kansas	Meade	853
218	Pipe: ANR TN-KY	2020	ANR Pipeline Co	Midwest	Intra-regional	Tennessee	Henry	Kentucky	Calloway	1,398
224	Pipe: ANR TN-MS	2020	ANR Pipeline Co	Midwest	South Central	Tennessee	Fayette	Mississippi	Marshall	1,375
281	Pipe: ANR Wisconsin-Chicago	2020	ANR Pipeline Co	Midwest	Intra-regional	Wisconsin	Walworth	Illinois	Mc Herny	700

Figure 3-103. Identifying Pipeline Connections in MarketBuilder and NGfast for Algonquin Gas Transmission and ANR Pipeline Company Networks

Transient hydraulic simulation analyses would be performed as needed in order to test the resiliency of the consolidated network of gas pipeline and storage facilities in the extended PJM service territory when gas or electric equipment failures are postulated in the vicinity of gas-fired generators. Transient hydraulic models have been completed for the following pipelines that are connected to multiple gas-fired generators (**Table 3-32**):

Table 3-32. Transient Hydraulic Pipeline Models for the Extended PJM Service Area

Completed Transient Model for Pipeline	Mileage	Capacity (mmcfd)	No. Power Plants
Algonquin Gas Transmission	1,131	3,080	33
ANR Pipeline Co	9,253	10,000	41
East Tennessee Natural Gas	1,526	1,860	25
Empire Pipeline Inc.	269	300	1
Millennium Pipeline	220	500	1
Tennessee Gas Pipeline	11,758	2,200	31
Texas Eastern Transmission	8,580	11,690	34
Texas Gas Transmission	5,946	3,800	17
Transcontinental Gas Pipeline	9,924	15,580	57

Following contingency events, the transient hydraulic pipeline models would capture the ability of the pipeline to use line-pack to sustain deliverability to all customers receiving gas during baseline operations, as well as the use of spare horsepower available at specific compressor stations. Line pack is the volume of gas contained within a pipeline that allows gas in one area of the pipeline's system to be delivered simultaneously elsewhere on the system.

The current status of the MarketBuilder-NGfast integration is as follows:

- Natural gas demand estimated by MarketBuilder at the state-level has been downscaled to the 1,600-plus LDCs considered in NGfast;
- The nearly 400 pipeline links in MarketBuilder have been partially downscaled to the 1,000-plus pipeline links in NGfast; and
- The natural gas contracts and suppliers have been determined for future gas-fired generators.

3.5 National Base Case – ERCOT

One of the largest challenges the NTRR Team faced in conducting the base case analysis was access to the ERCOT data and models. Access to this data is granted through FERC and the CEII process. Throughout the project, The NTRR team, along with DOE, attempted to receive access to this data with no response from FERC. Thus, the analysis for the base case (and extreme cases (Tasks 4 and 5) focused on EI and WI.

As a solution to model confidentiality, we propose the alternative to use the synthetic model developed by DOE support to carry out gas/electric dependency studies on the ERCOT system. However, this work was proposed for future analysis and thus not initiated under the NTRR project.

4. Task 4: Extreme Weather & Cyber Impact in the East

4.1 Introduction

Extreme physical events, like wildfires, heatwaves, hurricanes, and earthquakes, and cyber events have historically caused stressful system conditions in three North American interconnections. The main focus is to evaluate reliability and resilience for extended PJM area in the eastern U.S., which includes PJM and SERC but excluding Florida, under extreme weather and cyber conditions with natural gas adequacy analysis.

4.2 Collecting data and identifying the worst drought and winter storm case

To develop projected 2025 Extended PJM Extreme Summer Drought and Winter Storm Cases, extreme weather data should be collected, and generation additions and planned retirements by 2025 needs to be considered. The team starts the development by collecting information from different public data sources. Projections from different data sources are utilized and key findings and decisions are be reported in this section.

4.2.1 Findings, Decisions and Conclusion

The team could provide the following findings, and conclusions:

Data collection for extreme weather

1. Data collected from National Oceanic and Atmospheric Administration (NOAA) indicate that the average air temperature during summer is around 86 °F in most states of the extended PJM area, and the maximum air temperature usually under 105 °F.
2. The United States Geological Survey (USGS) () provides historical streamflow data of all states in the United States from 1930 to present. The state level 7-day average runoff data (1930 - 2020) for all states can be downloaded from the USGS website. U.S. Drought Monitor provides comprehensive statistic data and DSCI (Drought Severity and Coverage Index) information for each week of the selected time period and location. Data options are percent of area, total area, percent of population, and total population. Spatial scale choices include national, state, county, and urban areas, and many more.
3. The United States is divided and sub-divided into successively smaller hydrologic units which are classified into four levels: regions, subregions, accounting units, and cataloging units. The US is divided into 21 major geographic regions. The extended PJM area covers or partially covers HUC2 02 to 07 regions. According to drought data in the past 100 years, the typical severe drought years in the extended PJM area were 2002, 2007, and 2012.
4. Usually, we may assume that the power plants will be affected by the drought weather when the streamflow is lower than the 10th percentile of the historical value of this area. Historical data collected from USGS and U.S. Drought Monitor shows that some states (IL, KY, NC, NJ, TN, and VA) in the extended PJM area were more frequently affected by drought weather, while some other states (DC, MI, MD, OH, PA, and WV) were less affected by summer droughts.
5. Collected the plant-level streamflow and water temperature data for the 183 at-risk thermal units with once-through cooling system in extended PJM area. Collected the plant-level streamflow, water temperature, relatively humidity, and air temperature data for the 369 at-risk thermal units with recirculating cooling (RC) system in extended PJM area.

6. Collected winter storm weather data. Polar vortex can affect Midwest, South Central, and East Coast regions of North American, and will result in temperatures 20 to 35°F below average. By analyzing the winter storm events in the past few decades, three severe cold years in the extended PJM area were 1989, 2014 and 2018.
7. The team developed a credible summer drought scenario for the 2025 extended PJM model. The designed summer drought scenario is the historical drought condition which occurred in the summer of 2007.

Data collection for power generation and load in PJM and SERC regions

1. Data collection from EIA 860 Form show that, in extended PJM area, 86% of the generation capacity is provided by thermal power plants, 4% provided by hydro power plants, and 7% provided by wind and solar power plants.
2. Data collected from PJM load forecast report (2021) and SERC RRS annual report indicate that there are 22 load zones in PJM region and 13 load zones in the SERC region (excluding FL). In the next 10 years, the summer peak load will keep increasing for almost all the sub-regions of the PJM region, and the annual growth rate of summer peak load will be between 0.1% and 1.2%. Load growth is expected to be minimal across the central and southeastern SERC subregions.
3. The extreme cold weather will result in high electrical demand and generator outage rate. The team collected the outage rate data of generators and transmission lines.

Data collection for natural gas production and consumption in PJM and SERC regions

1. EIA monthly data was collected to determine the decrease in natural gas monthly injections during drought conditions compared with normal conditions.
2. Daily gas demand data was determined from pipeline electronic bulletin boards (EBB) during 2018 and 2019 which was scrubbed to remove gas demand for gas-fired generators – resulting in gas demand information for residential, commercial, and industrial customers.
3. Historical natural gas pipeline operations were investigated using DOT incident data submitted to and Hazardous Materials Safety Administration (PHMSA)by pipeline operators since 1970.
4. Historical gas production data was collected for the 2021 Texas Polar Vortex.

4.2.2 Historical summer drought and winter storm events

Summer drought data was collected for each state in PJM's service territory, to identify years and months of greatest drought intensity [70] (**Table 4-1**). Three years were identified as notable in terms of extent and duration of drought conditions: 2002, 2007, and 2012. It can be seen that year 2002 was identified by seven PJM states as the year with the most intense and longest duration of drought conditions, followed by 2007 (5 states) and 2012 (2 states).

Table 4-1. Drought Information by State in PJM Service Territory

State	Longest duration of drought (D1-D4) from 2000 to present	Most intense period of drought from 2000 to present	Year
DE	55 weeks beginning on October 30, 2001, and ending on November 12, 2002	week of August 20, 2002, where D4 affected 74.08% of Delaware land	2002
IL	54 weeks beginning on May 24, 2005, and ending on May 30, 2006	week of July 31, 2012, where D4 affected 8.39% of Illinois land	2012
IN	42 weeks beginning on July 23, 2002, and ending on May 6, 2003	week of August 7, 2012, where D4 affected 25.0% of Indiana land	2012
KY	46 weeks beginning on May 22, 2007, and ending on April 1, 2008	week of October 16, 2007, where D4 affected 16.15% of Kentucky land	2007
MD	58 weeks beginning on October 09, 2001, and ending on November 12, 2002	week of August 20, 2002, where D4 affected 39.88% of Maryland land	2002
MI	113 weeks beginning on August 26, 2008, and ending on October 19, 2010	week of August 28, 2007, where D3 affected 17.06% of Michigan land	2007
NJ	55 weeks beginning on October 30, 2001, and ending on November 12, 2002	week of August 20, 2002, where D4 affected 1.79% of New Jersey land	2002
NC	155 weeks beginning on January 4, 2000, and ending on December 17, 2002	week of December 11, 2007, where D4 affected 66.2% of North Carolina land	2007
OH	44 weeks beginning on July 23, 2002, and ending on May 20, 2003	week of September 4, 2007, where D3 affected 11.45% of Ohio land	2007
PA	68 weeks beginning on July 31, 2001, and ending on November 12, 2002	week of August 20, 2002, where D4 affected 0.06% of Pennsylvania land	2002
SC	156 weeks beginning on January 4, 2000, and ending on December 24, 2002	week of August 20, 2002, where D4 affected 50.71% of South Carolina land	2002
TN	116 weeks beginning on February 13, 2007, and ending on April 28, 2009	week of October 16, 2007, where D4 affected 70.49% of Tennessee land	2007
VA	103 weeks beginning on May 1, 2007, and ending on April 14, 2009	week of August 20, 2002, where D4 affected 30.53% of Virginia land	2002
WV	41 weeks beginning on May 29, 2007, and ending on March 4, 2008	week of March 12, 2002, where D3 affected 42.55% of Minnesota land	2002

The extent of drought conditions varies over time, with severe drought occurring in the extended PJM service area during 2002 and 2007. **Figure 4-1** shows drought conditions in 2007 were severe in southern portions of the extended PJM service territory and moderate in the northern sections.

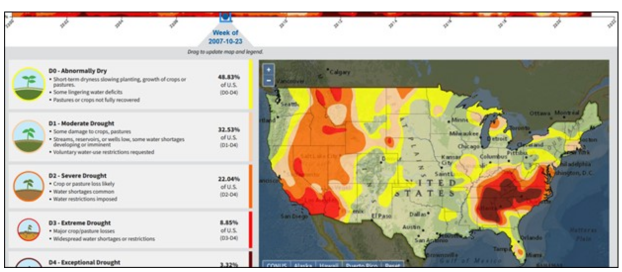


Figure 4-1. Drought Conditions During 2007

Historical daily weather data is available from NOAA's Weather Prediction Center [73]. During 2007, maximum daytime temperatures of greater than 90ºF throughout (almost) all of PJM on August 9th, 2007 (see **Figure 4-2**). Nighttime temperatures were recorded between 70 and 80ºF on August 9th, 2007, while maximum temperatures greater than 100ºF were seen in North and South Carolina. It can be concluded that these historical extreme temperatures combined with drought conditions would result in severe gas demands for electric generation in the extended PJM service territory.

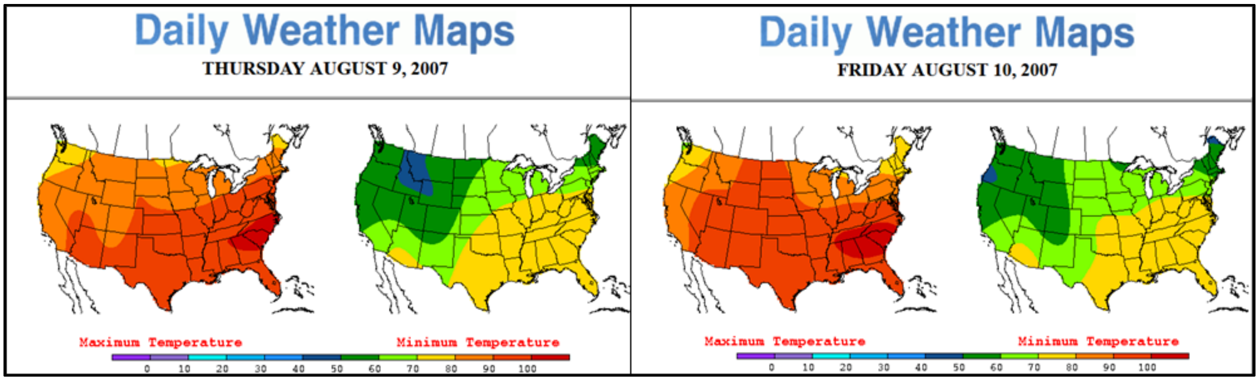


Figure 4-2. Daily Weather Conditions during August 9 and 10, 2007

The NTRR Gas Team is proposing that the analysis should be based on the 14-day period of cold weather during 1989/1990 selected by PJM in its "Fuel Security Analysis" [75]. During December 1989, record cold gripped most of the North American continent east of the Rocky Mountains [76]. December 1989 was the coldest December in over 100 years in the Lake Erie snowbelt of Ohio, Pennsylvania, and New York. Mean temperatures of −9°C were 7°C lower than average and extreme minima reached −30°C. Snow fell on 20 to 25 days of the month and snowfall totals of 100 to 200 cm were twice the December average [77]. **Figure 4-3** shows the daily temperature variation during December 1989 at Erie, PA [78].

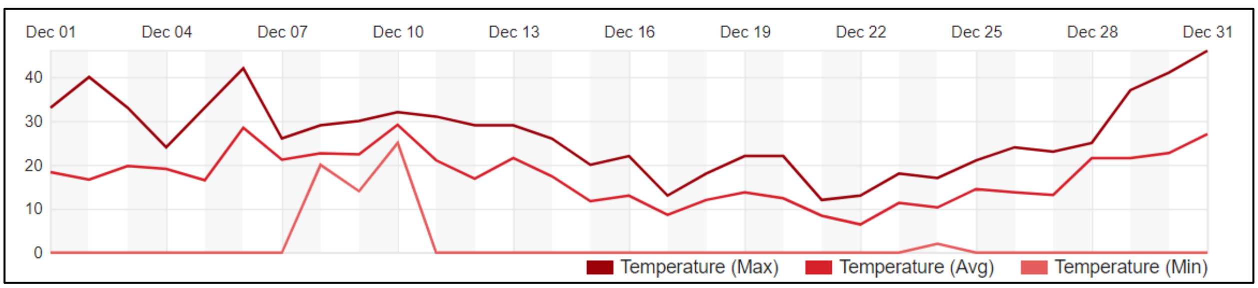


Figure 4-3. Historical Variation in Daily Temperatures during December 1990 at Erie, PA

The PJM fuel security analysis modeled a 14-day cold weather duration based on historical weather analysis. This study focuses on cold weather events because risks to PJM generation's ability to procure adequate fuel to serve load is most prominent during the winter.

The 1989/1990 winter was particularly severe, with both an extended cold period and weather eliciting an extreme peak. For 14 days, the average wind-adjusted temperature across the PJM footprint was less than 20 degrees (90th percentile daily winter weather) and the single coldest day produced a 95/5 (once in 20 years) peak load. Therefore, the 1989/1990 winter could be a historical basis for establishing 14 days as the extreme winter event duration for the winter storm.

4.2.3 Data sources for Extreme Case Development

To evaluate the impact of summer drought events on the 2025 extended PJM area, the first step was to collect the drought weather data and the energy infrastructure data. There are several data sources for historical drought weather and bulk power system. In this task, data are mainly collected from the following sources,

- USGS [54], United State Drought Monitor [55], and NOAA [56]

- EIA 860 Form [11] and EIA 923 Form [57]
- PJM load forecast report, SERC annual report
- PJM data miner, EIA Data Sets

To evaluate the impact of winter storm/polar vortex events on the 2025 extended PJM area, the team needs to collect winter storm weather data and the energy infrastructure outage data. In this task, data are mainly collected from the following sources:

- National Oceanic and Atmospheric Administration (NOAA),
- Generating Availability Data System (GADS), and
- Transmission Availability Data System (TADS)

4.2.3.1 USGS

USGS Water Watch operated a nationwide network of more than 8,200 stream gauges, and almost all USGS stream gauges are operated in real time. Streamflow information can be derived from these stream gauges and is available at https://waterwatch.usgs.gov. Historical streamflow conditions by State, expressed as runoff, beginning in water year 1901, can be accessed at the website. These tables are updated every few months to reflect the most recent streamflow data.

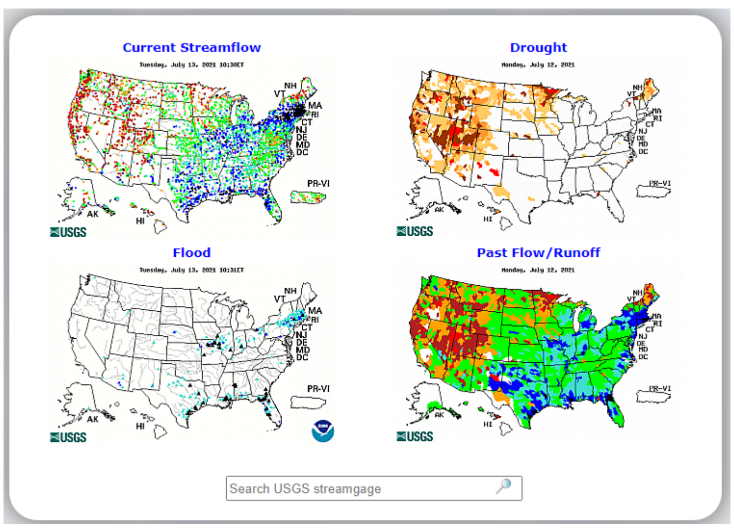


Figure 4-4. USGS Water Watch website

4.2.3.2 U.S. Drought Monitor

The U.S. Drought Monitor (USDM) is a map (**Figure 4-5**) that is updated each Thursday to show the location and intensity of drought across the US. The USDM uses a five-category system, labeled Abnormally Dry or D0, (a precursor to drought, not actually drought), and Moderate (D1), Severe (D2), Extreme (D3) and Exceptional (D4) Drought. Drought categories show experts' assessments of conditions related to dryness and drought including observations of how much water is available in streams, lakes, and soils compared to usual for the same time of year. The U.S. Drought Monitor began in 2000 and is a collaboration between the NDMC, NOAA and the United States Department of Agriculture (USDA), who share the weekly author role for the product. The data and statistics are available to the public.

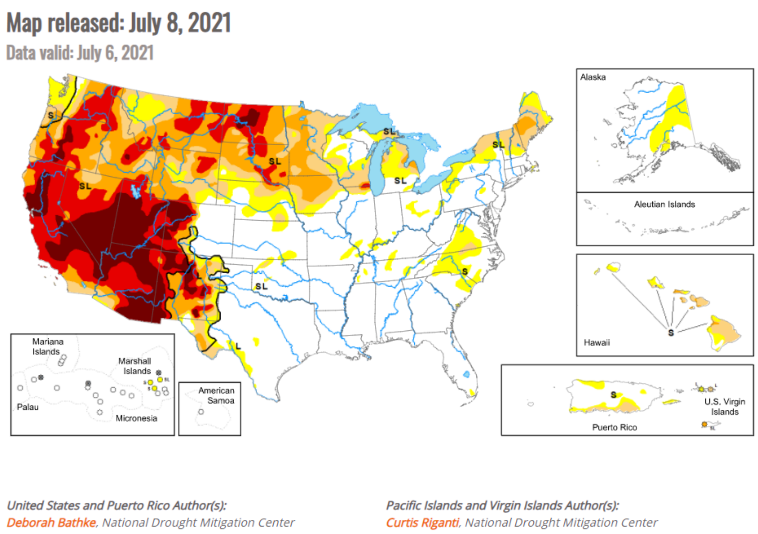


Figure 4-5. Drought Monitor (USDM) map

4.2.3.3 NOAA

NOAA provides free access to NOAA National Climate Data Center (NCDC's) archive of global historical weather and climate data in addition to station history information (see **Figure 4-6**). These data include quality controlled daily, monthly, seasonal, and yearly measurements of temperature, precipitation, wind, and degree days as well as radar data and 30-year climate normals.

Figure 4-6. NOAA climate data online

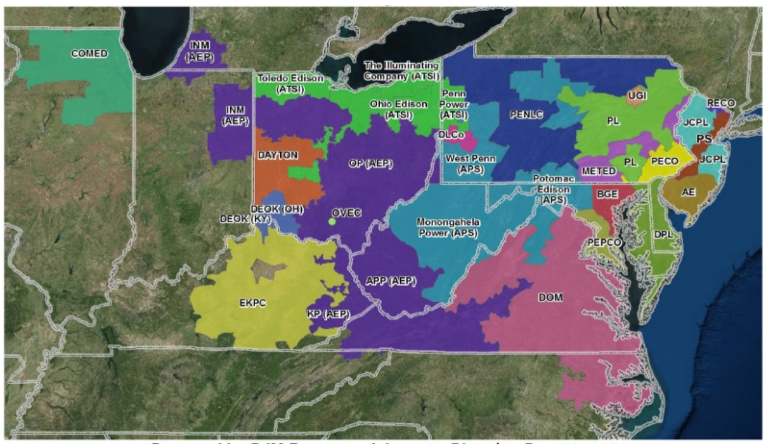
4.2.3.4 EIA 860 and EIA 923

The survey Form EIA-860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity. The survey Form EIA-923 collects detailed electric power data -- monthly and annually -- on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level. Specific survey information provided:

- Schedule 2 - fuel receipts and costs.
- Schedules 3A & 5A - generator data including generation, fuel consumption and stocks.
- Schedule 4 - fossil fuel stocks.
- Schedules 6 & 7 - non-utility source and disposition of electricity.
- Schedules 8A-F - environmental data.

4.2.3.5 Load projections from PJM and SERC reports

PJM load forecast report [58] provides long-term forecasts of peak loads, net energy, load management, distributed solar generation, and plug-in electric vehicles for each PJM zone, region, locational deliverability area (LDA), and the total RTO. According to the report released in 2021, summer peak load growth for the PJM RTO is projected to average 0.3% per year over the next 10 years, and 0.2% over the next 15 years. The PJM RTO summer peak is forecasted to be 153,759 MW in 2031, a 10-year increase of 4,535 MW, and reaches 154,728 MW in 2036, a 15-year increase of 5,504 MW. Annualized 10-year growth rates for individual zones range from -1.2% to 0.9%.



Prepared by PJM Resource Adequacy Planning Department

Figure 4-7. PJM load area

Data Miner (see **Figure 4-8**) is PJM's enhanced data management tool, giving members and non-members easier, faster, and more reliable access to public data formerly posted on pjm.com. Users can manually search and filter data with Data Miner, and download generation, load, load forecast, locational marginal prices, and system information.

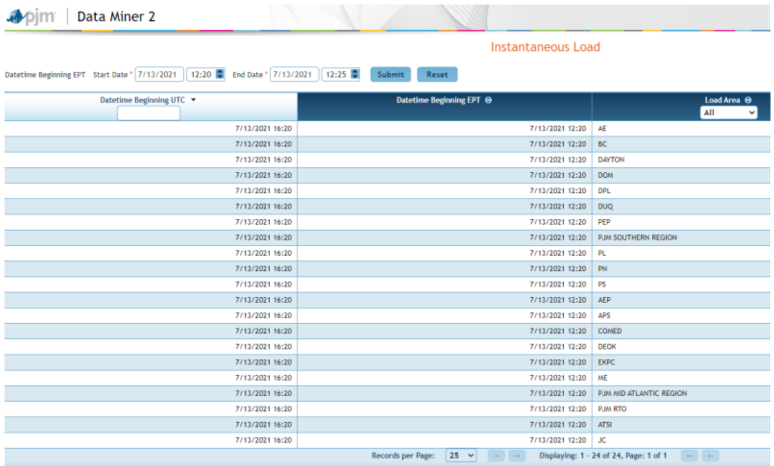


Figure 4-8. PJM Data Miner

4.2.3.6 Generator and transmission line outage data

GADS (Generating Availability Data System) is recognized as a valuable source of reliability information for total unit and major equipment groups and is widely used by industry analysts in a variety of applications. Through GADS, NERC collects information about the performance of electric generating equipment and provides assistance to those researching information on power plant outages. GADS also supports equipment availability analyses and other decision-making processes in the industry. GADS data is also used in conducting assessments of generation resources and improving their performance.

GADS is a mandatory industry program for conventional generating units that are 20 MW and larger. GADS is open to any organization that operates electric generating facilities and is willing to follow the GADS reporting requirements specified in the GADS Data Reporting Instructions (DRI).

TADS collects transmission outage data in a common format for:

- Bulk Electric System AC Circuits (Overhead and Underground).
- Transmission Transformers (No Generator Step-up Units).
- Bulk Electric System AC/DC Back-to-Back Converters.
- Bulk Electric System DC Circuits.

TADS efforts began in 2006 with the formation of the TADS Task Force under the NERC Planning Committee. This task force designed TADS and the associated processes for collecting TADS data. On June 30, 2009, the task force issued its first reports for data collected in 2008. On July 1, 2009, the task force was retired and replaced with the TADS Working Group. This change recognized the ongoing design and oversight of TADS that is more appropriately assigned to a working group than a task force. NERC uses the information to develop transmission metrics that analyze outage frequency, duration, causes, and many other factors related to transmission outages.

4.3 Impact of summer drought on natural gas and bulk power system in extended PJM

After gathered the weather and natural gas/power system infrastructure information of PJM and SERC regions, the impact model of extreme weather on the natural gas and power system should be developed. The team formulated the impact of summer drought on usable capacity of thermoelectric and hydroelectric generators. The impact of air temperature on transmission ratings were also analyzed. In addition, for the summer seasons, the temperature-humidity index (THI) is used as the weather parameter to analyze the impact of hot weather on electric demand. Regarding the natural gas system, the team compared the monthly gas injections of extended PJM area during drought and normal conditions. Impact of summer drought on natural gas production was studied. The impact of air temperature on gas demand was also investigated. Details of the model development procedure are presented in this section.

4.3.1 Findings, Decisions and Conclusion

Through the abovementioned tasks, the team could provide the following findings, and conclusions:

1. Thermal units using fresh surface water to cool systems are at-risk units. To accurately model the impact of summer drought on thermal power plants, the team formulated analytical models which evaluate the impact of weather condition on daily usable capacity of units by heat exchange equations. According to the heat balance of once-through cooling system, the usable capacity of the unit is affected by the available water flow, the maximum rise in cooling water temperature between the condenser inlet and outlet, regulatory limits of water discharged by a plant, thermal efficiency, etc. Also, the usable capacity of a unit with closed-cycle cooling system is affected by water temperature, air temperature, relative humidity, available water flow, etc. In addition, the usable capacity of a combustion turbine is affected by ambient air temperature. Past research works show that for every 1°C increases in ambient temperature above 15°C, the power capacity of a combustion turbine generator drops by about 0.7-1.0%. To validate the effectiveness of the analytical derating modeling methods, the team compared the calculated usable capacity and the actual power output of thermal units in the extended PJM area. The results show that the actual power output usually did not violate the calculated usable capacity, which validated the rationality and effectiveness of the derating models.
2. During summer droughts, the loss of hydro power generation is proportional to the loss of streamflow. The team collected the plant-level streamflow data and the hydro generation data, then calculated the daily usable capacity for each hydro plant in the extended PJM area according to the relationship between water flow and generator power output. And studied the correlations between hydroelectric generation and water flow during summer. The results show that the correlations are very strong.
3. By analyzing the rating data of transmission lines in PJM region, under different ambient air temperatures, transmission line rating decreases 0.5% per ℃ averagely when air temperature increases from 0 ℃ (32F) to 35 ℃ (95F).
4. The electric load has a very strong correlation with air temperature. The team collected the hourly load data and temperature data of PJM and SERC regions. To model the impact of temperature and humidity on electric load during summer, THI is utilized. By analyzing the relationship between THI and summer load for each load zone in the extended PJM grid, the team found that the correlations between THI and load value is very strong. Daily maximum load increases when the THI value goes up. At THI values less than 65, there are minimal load response to weather conditions. At THI values around the high 70s or higher, there is often some moderation in load response from mid-range THI values.
5. During a long-term drought, natural gas-fired generation increases to compensate for curtailment of hydroelectric, nuclear, and coal-fired generation. Natural gas demand for electric generation increased significantly during the summer months of July to September 2007, which is not seen during 2012. The gas system was under greater stress during 2007, consistent with a hypothetical but plausible drought scenario impacting gas-fired generation in the combined PJM/SERC region.

6. Comparison of monthly gas injections during drought and normal conditions are conducted. A similar monthly injection pattern occurs during normal conditions, with increased (nearly constant) injections during the months of May to September, which tapers off during the winter months. However, during drought conditions, monthly gas injections during the months of May to September are lower compared with normal conditions, reflecting the increase in gas demand for power generation. Then, the relationship between storage injections and demand for gas-fired electric generation is also studied.
7. Drought conditions have the potential to affect natural gas production in the extended PJM service area. Water use for well stimulation by gas production basin has been collected and the impacts of drought conditions on future gas production were predicted based on the availability of water and the mean water requirements per well.
8. It is well-known that temperature has huge impact on gas consumption. The team investigated the relationship between daily average temperature against the daily total gas consumption as a function of state, based on interstate gas pipeline nomination data for 2019 and 2020. The results show that daily gas consumption always changes conversely against temperature.

4.3.2 Impact of summer drought on usable capacity of thermoelectric and hydroelectric generators

4.3.2.1 Hydroelectric generator capacity derating

The generating capacity of a hydroelectric power plant can be calculated according to the flow rate of the water passing through the turbine [59] [60], as shown in the following equation:

$$P_h = \eta \cdot \rho_w \cdot Q \cdot g \cdot H$$

where, P_h is the power output of the hydroelectric plant, η is the efficiency of the generator, ρ_w is the density of water, Q is the flow rate of the water, g is the gravity acceleration constant, H is the net hydraulic head acting on the turbine. From the above equation, it can be found that the usable capacity of a specific hydroelectric power plant is determined by the available water flow [73] [74]. The strong correlations between state-level hydroelectric monthly generation and state-level flow rate were validated by the collected historical data, as shown in **Figure 4-9.** Correlations between monthly hydroelectric generation and water flow during summer

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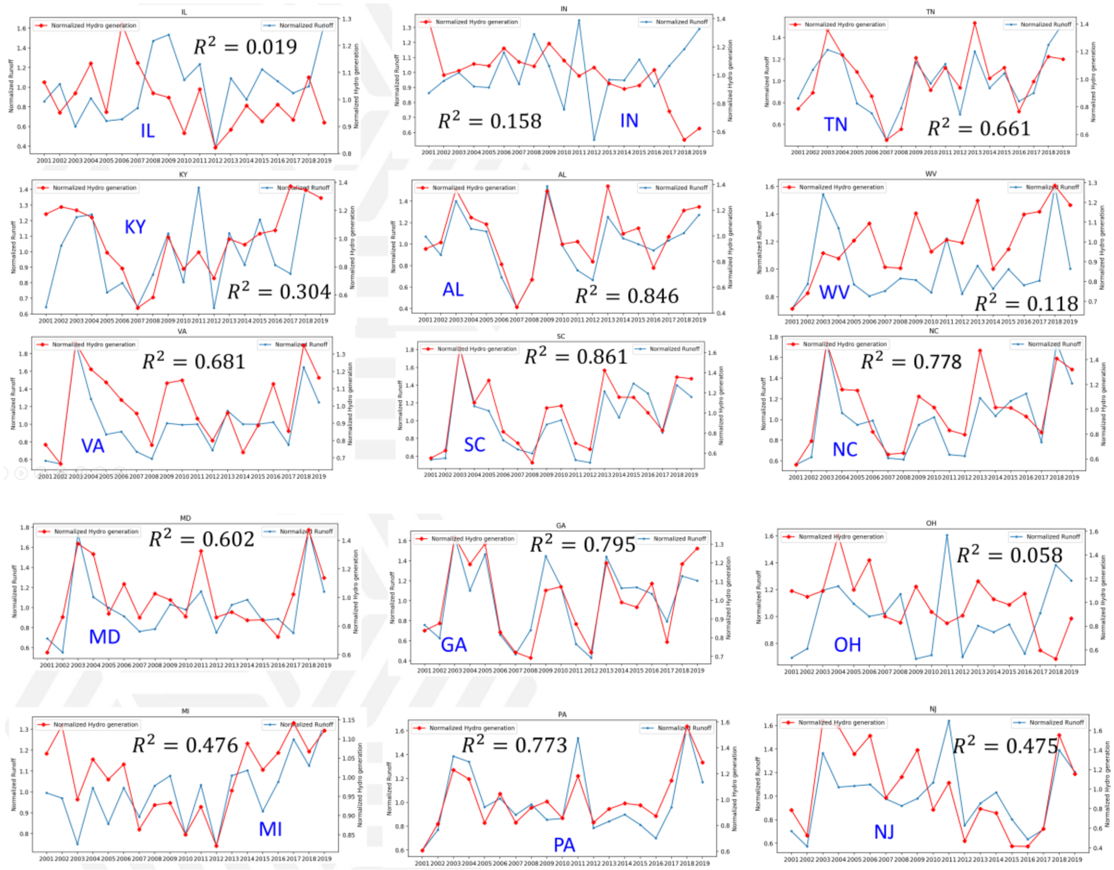

Figure 4-9. Correlations between monthly hydroelectric generation and water flow during summer

4.3.2.2 Thermoelectric power plant capacity derating

To estimate the impact of summer drought weather on generation, the thermoelectric power plants can be categorized into two categories: at-risk unit and low-risk unit. The at-risk thermoelectric plants include all units using fresh surface water to cool the generation system [63] [64]. Besides, combustion turbine (CT) is also defined as at-risk unit. Usually there are three different types of cooling system adopted by thermoelectric power plant, namely once-through (ON) cooling, recirculating (RC) cooling, and air cooling. The ON and RC cooling systems reject the heat by water withdrawal from nearby rive or underground. Thus, the usable capacity of water-cooling thermoelectric power plant is affected by available cooling water. For the at-risk thermoelectric power plant with ON cooling systems, the usable capacity of the generator can be calculated using the following equation [65] [66]:

$$P_{on} = \frac{\min\left(\gamma Q_i,\ W_{on}\right) \cdot \rho_w \cdot C_{p,w} \cdot \max\left(\min(Tl_{max} - T_w,\ \triangle Tl_{max}),0\right)}{\frac{1-\eta_{net,i}-k_{os}}{\eta_{net,i}}}$$

where, P_{on} is the maximum usable capacity of the generator, γ is the maximum fraction of streamflow available for cooling the power plant, W_{on} is the water withdrawals when the plant operates at rated capacity, Q_i is the real-time streamflow of the river from which the plant withdraw cooling water, ρ_w is the density of cooling water, $C_{p,w}$ is the heat capacity of water, Tl_{max} is the maximum permissible, $\triangle$

Tl_{max} is the maximum permissible water temperature rise through the condenser water temperature discharged to rivers, T_w is the temperature of the inlet water, $\eta_{net,i}$ is the net efficiency of the plant, k_{os} is the fraction of heat lost to heat sinks.

Using the above equation, the team calculated the daily usable capacity of all at-risk once-through plants in PJM and SERC region. **Figure 4-10** and **Figure 4-11** show the calculated usable capacity of plant James M. Barry at state Alabama during summer drought event in 2007 when the maximum discharge water temperature limit is considered or not. By comparing **Figure 4-10** and **Figure 4-11**, we can also find that the usable capacity of the unit reduced more when consider the water temperature discharge limit. For instance, the usable capacity (with regulatory limit) is zero during 8/15/2007 and 8/25/2007 as the inlet water temperature approached 32 ◦C. However, if the regulatory limit is not considered, the usable capacity was almost not affected.

To further validate the effectiveness of the capacity derating model, we compared the calculated usable capacity with the actual power output of once through generators in PJM and SERC region. **Figure 4-12** shows the calculated usable capacity of plant Brunner Island at state PA from 2012 to 2013. And the green line shows the actual power output of the plant. It can be found that the green line is always below the orange line, which means the actual power output did not violate the calculated usable capacity (regulation ignored).

The usable capacity of thermoelectric power plant with recirculating cooling system can be calculated using a similar heat balance equation. Thermoelectric facilities employing a combustion turbine generator require little to no water for cooling. Power generation at combustion turbine facilities is affected mainly by the ambient dry bulb temperature of the air. Based on the results of empirical studies, simple-cycle combustion turbines are estimated to lose about 0.7-1.0% percent of capacity for every degree Celsius above 15 ℃.

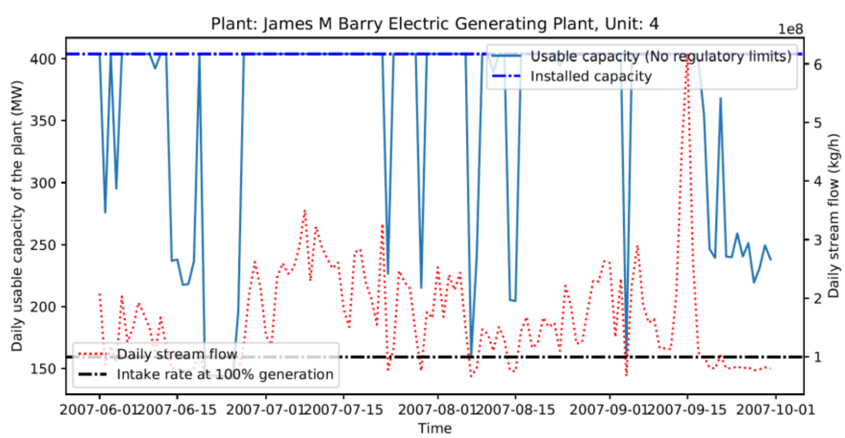

Figure 4-10. Calculated daily usable capacity of plant James M. Barry during summer of 2007 without water temperature discharge limit

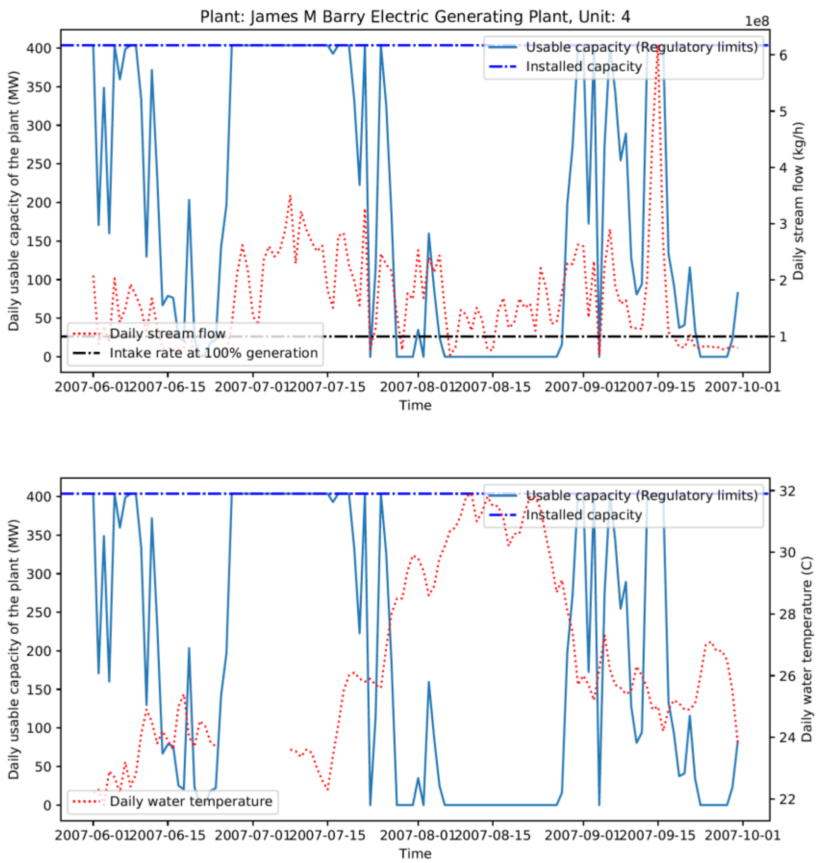

Figure 4-11. Calculated daily usable capacity of plant James M. Barry during summer of 2007 considering water temperature discharge limit

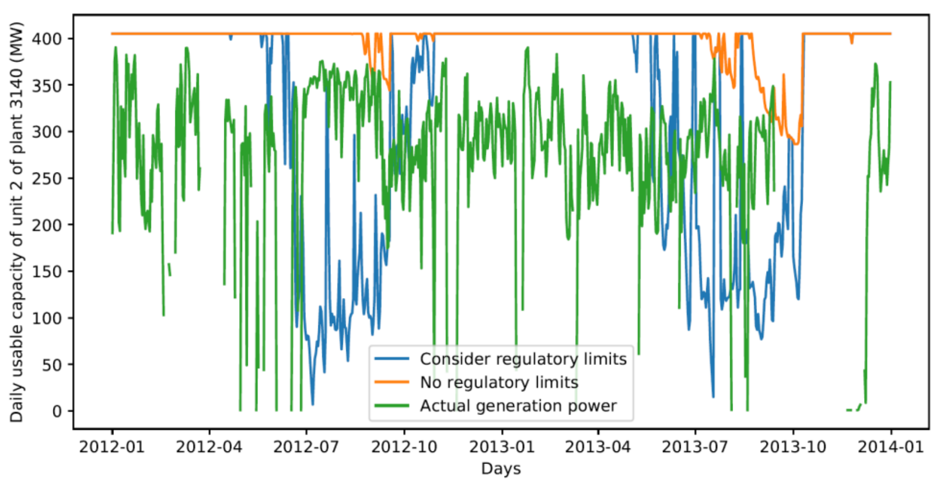

Figure 4-12. Calculated usable capacity and actual power output of unit 2 of plant 3140

4.3.3 Impact of air temperature on ratings of transmission lines

The operations of transmission lines are easily affected by extreme high temperature. When the ambient air temperature is high, the ratings of transmission lines will decrease. To avoid surpassing a transmission line's maximum operating temperature, operators typically curtail the current in an at-risk conductor such that thermal limits are satisfied. Thus, electric power cables are generally given a 'rated ampacity', which represents the maximum current for which conductor temperature limits are met under standard ambient temperature and wind conditions. But hotter air temperatures due to may reduce the effective ampacity of transmission lines by interfering with their ability to dissipate heat. So, several emergency ratings are also given to system operators. From PJM website, three sets of thermal limits are provided for all monitored equipment:

- Normal limit
- Emergency limit
- Load dump limit

PJM systems expect Normal (continuous), Emergency (long term and short-term emergency are set equal unless specifically approved otherwise) and Load Dump limits. Eight ambient temperatures are used with a set for the night period and a set for the day period; thus, 16 sets of three ratings are provided for each monitored facility. Ambient temperatures of 95°, 86°, 77°, 68°, 59°, 50°, 41°, and 32°F for both day and night periods are collated to constitute the 16 rating set selections. All Transmission Owners' and the PJM RTO's security analysis programs must be able to handle all 16 sets and allow operating personnel to select the appropriate rating set to be used for system operation. With a minimum of two set selections required daily (day/night), the Transmission Owner and the PJM RTO security analysis programs use these 16 ambient temperature rating sets for monitoring actual and contingency overloads. All temperatures associated with the ambient temperature rating data sets are in degrees Fahrenheit.

The team collected the rating information of 20,000+ transmission lines in PJM area [67]. Based on the gathered data, the line derating factor is calculated as follows:

$$Derating\ factor = \frac{R_{32} - R_{95}}{R_{77} * 63}$$

where, R_{32}, R_{77}, and R_{95} are the ratings when temperature is 32 F, 77 F, and 95 F, respectively. From the results shown in **Figure 4-13**, it can be found that the average derating factor is about 0.5%/°C form 32°F to 95°F.

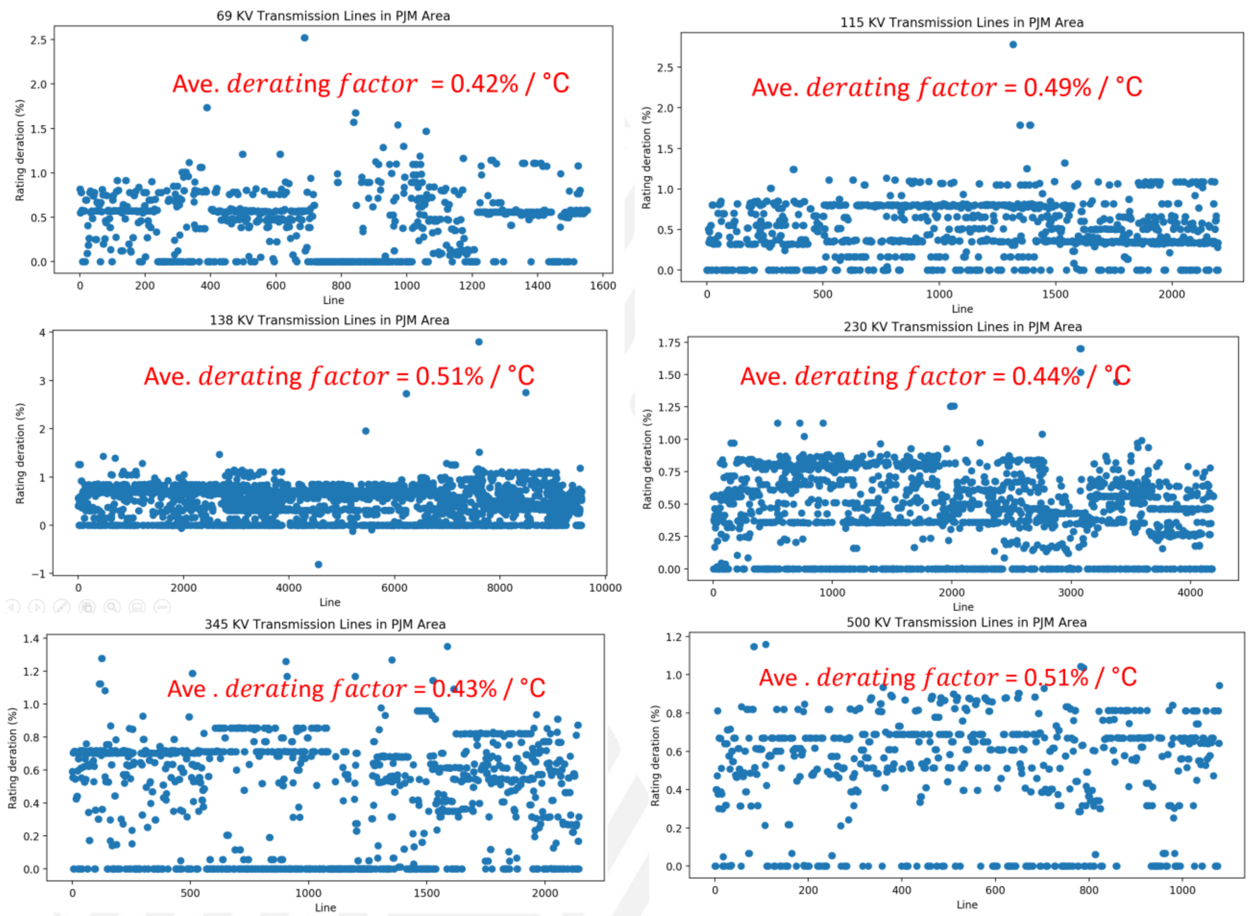

Figure 4-13. Derating factors of different voltage level of transmission lines in PJM region

4.3.4 Impact of summer drought on electric load

To model the impact of hot weather on electric load, the team collected the historical load data and weather data of PJM region during summer (Jun., Jul., Aug, and Sep.). Firstly, we calculated the THI value using the following equation [68]:

$$\begin{cases} THI = Temp - 0.55 \times (1 - Hum) \times (Temp - 58), if\ Temp > 58 \\ THI = Temp, if\ Temp\ \leq 58 \end{cases}$$

where, Temp = Dry bulb temperature, Hum = Relative humidity (where 100% = 1). For each load zone, we used linear spline fitting functions to map the relationship between THI and electric load. The relationships between THI and load of AE, APS, and ATSI zones are shown in **Figure 4-14**. The daily maximum load increases when the THI value goes up. At THI values less than 65, there are minimal load response to weather conditions. At THI values around the high 70s and higher, there is often some moderation in load response from mid-range THI values. This reflects some degree of HVAC saturation.

4.3.5 Impact of summer drought on natural gas storage

A summer drought would have limited impact on natural gas operations. Temperature shifts are not expected to have direct or indirect impacts on pipelines. Soil cover and water moderate temperature effects; pipelines are already designed to accommodate significant temperature variations. There is no documented relationship between drought conditions and pipeline failure. However, extreme heat associated with a long-term drought can contribute to natural gas equipment failures.

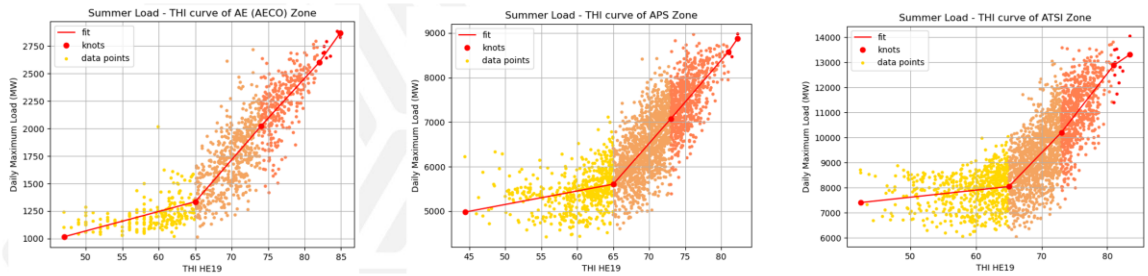

Figure 4-14. The impact of THI parameter on load of AE, APS, and ATSI

An indirect impact of a summer drought on the natural gas sector is the increased demand for gas-fired electric generation. During 2021, California relied more on gas fired-power plants as extreme drought cut hydropower output by more than half, while frequent wildfires often shut electricity imports from other states.

Decreases in electric transmission and electric generation capacity would increase reliance on fast-start gas-fired generation and hence underground gas storage which are used to provide gas supply on short notice, particularly in summer[6]. The net effect would be a stronger reliance on underground gas storage in summer, and possibly increased gas use of stored gas. This would reduce the amount of gas injected during summer into underground gas storage and its availability during the upcoming winter months.

Natural gas storage supplements natural gas production during periods of high demand. During the injection season, which is defined from April 1 to October 31, natural gas is typically injected into underground storage facilities from the interstate pipeline system; these facilities can be old natural gas wells or reservoirs no longer producing, salt caverns, or aquifers. Natural gas is then withdrawn from storage and delivered back into the pipeline network during the withdrawal season—November 1 to March 31—as needed to meet customer demand during the winter season.

EIA monthly data was collected to determine the decrease in natural gas monthly injections during drought conditions compared with normal conditions. **Figure 4-15** compares the monthly injections during the drought years of 2002, 2007, and 2012 with more typical conditions during 2003, 2008, and 2013.

[6] The deregulation of underground storage combined with other factors such as the growth in the number of natural gas-fired electricity generating plants has placed a premium on high-deliverability storage facilities. These facilities are used almost exclusively to serve third-party customers who can most benefit from the characteristics of these facilities, such as marketers and electricity generators.

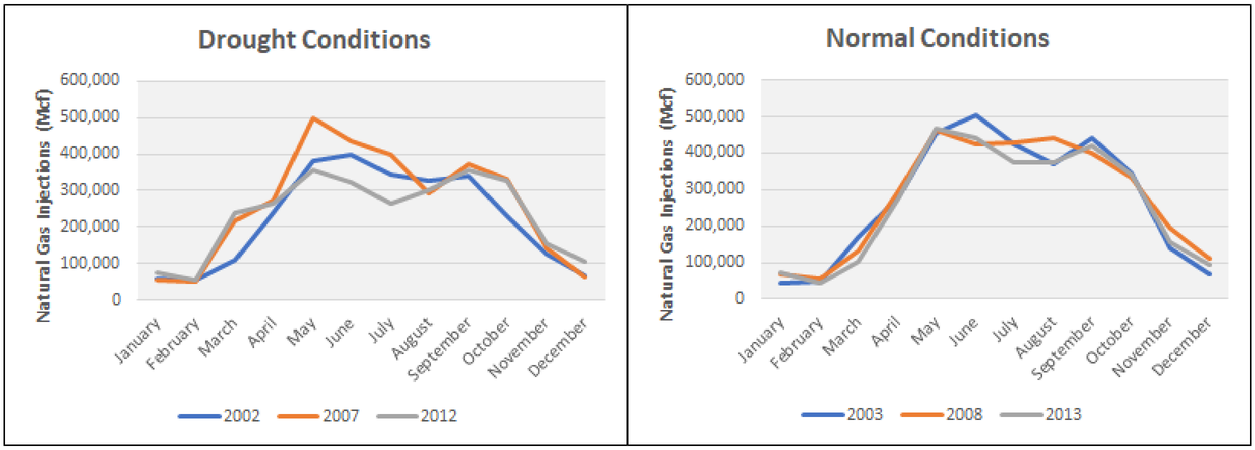

Figure 4-15. Comparison of Monthly Gas Injections during Drought and Normal Conditions

It can be seen in **Figure 4-15** that a similar monthly injection pattern occurs during normal conditions, with increased (nearly constant) injections during the months of May to September, which tapers off during the winter months. However, during drought conditions, monthly gas injections during the months of May to September are lower compared with normal conditions, reflecting the increase in gas demand for power generation.

This relationship between storage injections and demand for gas-fired electric generation is provided in **Figure 4-16** based on interstate pipeline nominations7 data for 2007. Prior to the onset of drought conditions during 2007, injection volumes increase after April 2007 to June 2007, while the gas demand for electric generation remains low. As the need for gas-fired generation increases during the summer months, the gas volumes for underground storage injections decrease and do not reach prior injection volumes before the start of the winter heating season in November. The 2007 drought resulted in low gas storage volumes but luckily, December 2007 through February 2008 was about average in the contiguous U.S. and average winter season temperature was 33.2°F (0.6°C), which was 0.2°F (0.1°C) above the 20th Century mean [69].

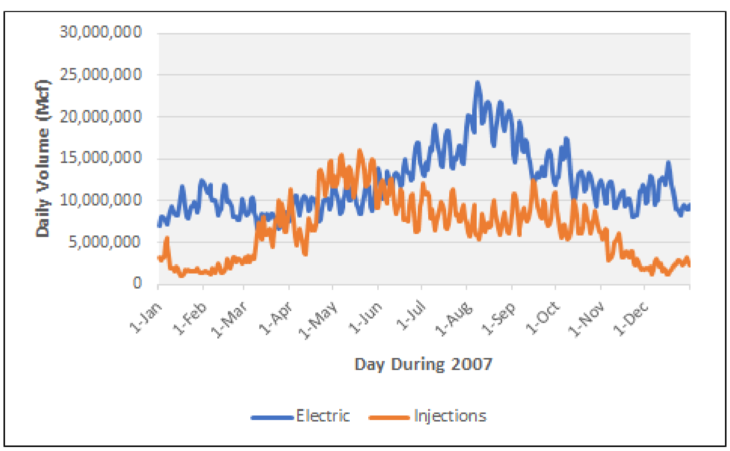

Figure 4-16. Daily Natural Gas Injections and Demand for Electric Generation during 2007

[7] Nomination is the process through which pipelines schedule gas for shippers or adjust gas flows during the Gas Day for final delivery.

4.3.6 Impact of summer drought on natural gas production

Hydraulic fracturing, commonly known as fracking, injects high pressure volumes of water, sand, and chemicals into existing wells to unlock natural gas and oil. The technique fractures the rock to get to the otherwise unreachable deposits. Fracking is water-intensive and can use up to 3 to 5 million gallons of water in a single operation according to the Sierra Club. Drought conditions have the potential to affect natural gas production in the extended PJM service area. Water use for well stimulation by gas production basin has been collected [74] and the impacts of drought conditions on future gas production were predicted based on the availability of water and the mean water requirements per well (see **Figure 4-17**).

Basin	Units	p2.5	Mean	p97.5
Appalachian	gal/well	1.07E+07	1.11E+07	1.14E+07
Gulf Coast	gal/well	7.98E+06	8.19E+06	8.40E+06
Arkla	gal/well	1.27E+07	1.38E+07	1.48E+07
East Texas	gal/well	5.06E+06	6.42E+06	7.77E+06
Arkoma	gal/well	7.08E+06	8.37E+06	9.67E+06
South Oklahoma	gal/well	5.64E+06	7.03E+06	8.43E+06
Anadarko	gal/well	8.14E+06	8.71E+06	9.28E+06
Strawn	gal/well	4.51E+06	5.35E+06	6.19E+06
Fort Worth	gal/well	1.43E+06	2.15E+06	2.88E+06
Permian	gal/well	9.08E+06	9.52E+06	9.95E+06
Uinta	gal/well	1.73E+06	2.29E+06	2.86E+06
Green River	gal/well	9.00E+05	9.86E+05	1.07E+06
Piceance	gal/well	3.37E+06	3.58E+06	3.80E+06

Figure 4-17. Water Use for Gas Well Stimulation

4.3.7 Impact of summer drought on natural gas demand

Extremely hot weather can adversely affect electric generation by restricting plant cooling, sources of cooling water, and hydroelectric generation due to drought or flooding, as well as reducing facility ratings. The PJM and SERC regions have faced mild to severe drought conditions for multiple years.

The "2020 SERC Reliability Risk Report" identified the 2007 drought season as an example of extreme weather impacting its operations [71]. Historically, drought-created increases in water temperatures and decreases in water levels led to power plant curtailments. For example, during the 2007-2008 drought in the southeast U.S., a number of nuclear and coal generators were forced to shut down or curtail output, due to cooling water temperature limitations [72].

It would be expected that natural gas-fired generation would increase to compensate for curtailment of hydroelectric, nuclear, and coal generation. **Figure 4-18** compares the daily gas demand for electric generation during 2007 and 2012 based on gas pipeline nominations data (nominations data is unavailable for 2002). The greatest impact on gas-fired generation occurred during 2007, with extremely high peaks during the summer months of July to September. The maximum gas demand for gas-fired generation occurred on August 9th-10th during 2007 which correlates with the then-current drought conditions throughout the U.S. during that week. However, the maximum gas demand for gas-fired generation occurred on late July-early August during 2012, while the maximum extent of drought conditions in Illinois and Indiana occurred later, during the month of November 2012. It was concluded that 2012 would not be a good candidate for analyzing electric-gas coordination issues under drought conditions.

The much higher electric generation during 2007 indicates that this historical event may be appropriate for the hypothetical but plausible drought scenario involving the gas system in the combined PJM/SERC region.

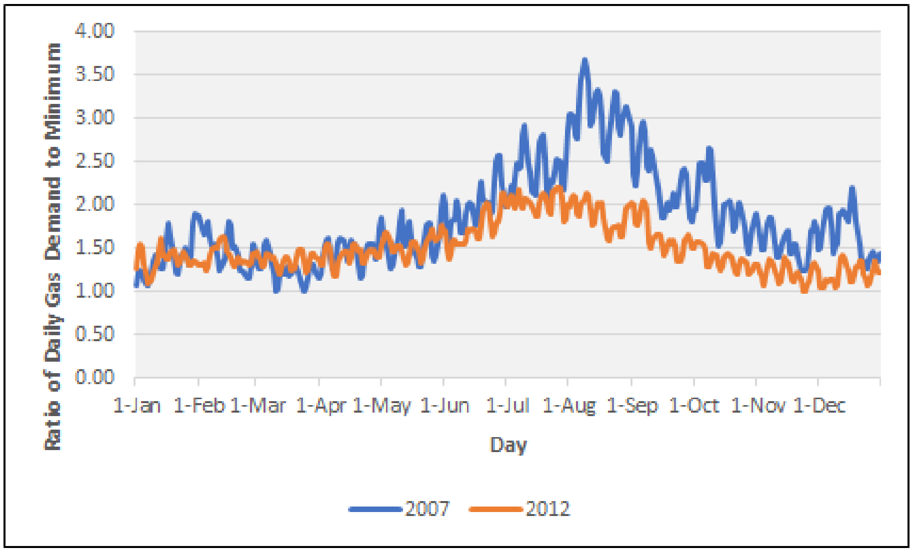

Figure 4-18. Comparison of Natural Gas Demand for Electric Generation for 2007 and 2012

It is well-known that temperature has huge impact on gas consumption. Typically, gas consumption (excluding demand for gas-fired electric generation) changes dramatically with temperature: when the temperature drops continuously, gas consumption rises accordingly.

The daily natural gas demand for the extreme weather conditions assumed during the postulated summer drought followed by extreme cold weather will differ from normal averages. It is therefore necessary to predict the variation in daily natural gas demand as a function of location and date to match the extreme weather conditions during the summer drought and extreme winter event.

In this analysis, the temperature is the only considered weather element as it directly reflects gas consumption for heating. This work is achieved based on daily analysis on gas consumption and temperature.

Daily gas demand data was determined from pipeline EBBs during 2018 and 2019 which was scrubbed to remove gas demand for gas-fired generators – resulting in gas demand information for residential, commercial, and industrial customers. Daily average temperatures were estimated from hourly temperature readings at multiple National Weather Service (NWS) stations.

Figure 4-19 visually shows the relationship between daily average temperature against the daily total gas consumption as a function of state, based on interstate gas pipeline nomination data for 2019 and 2020.

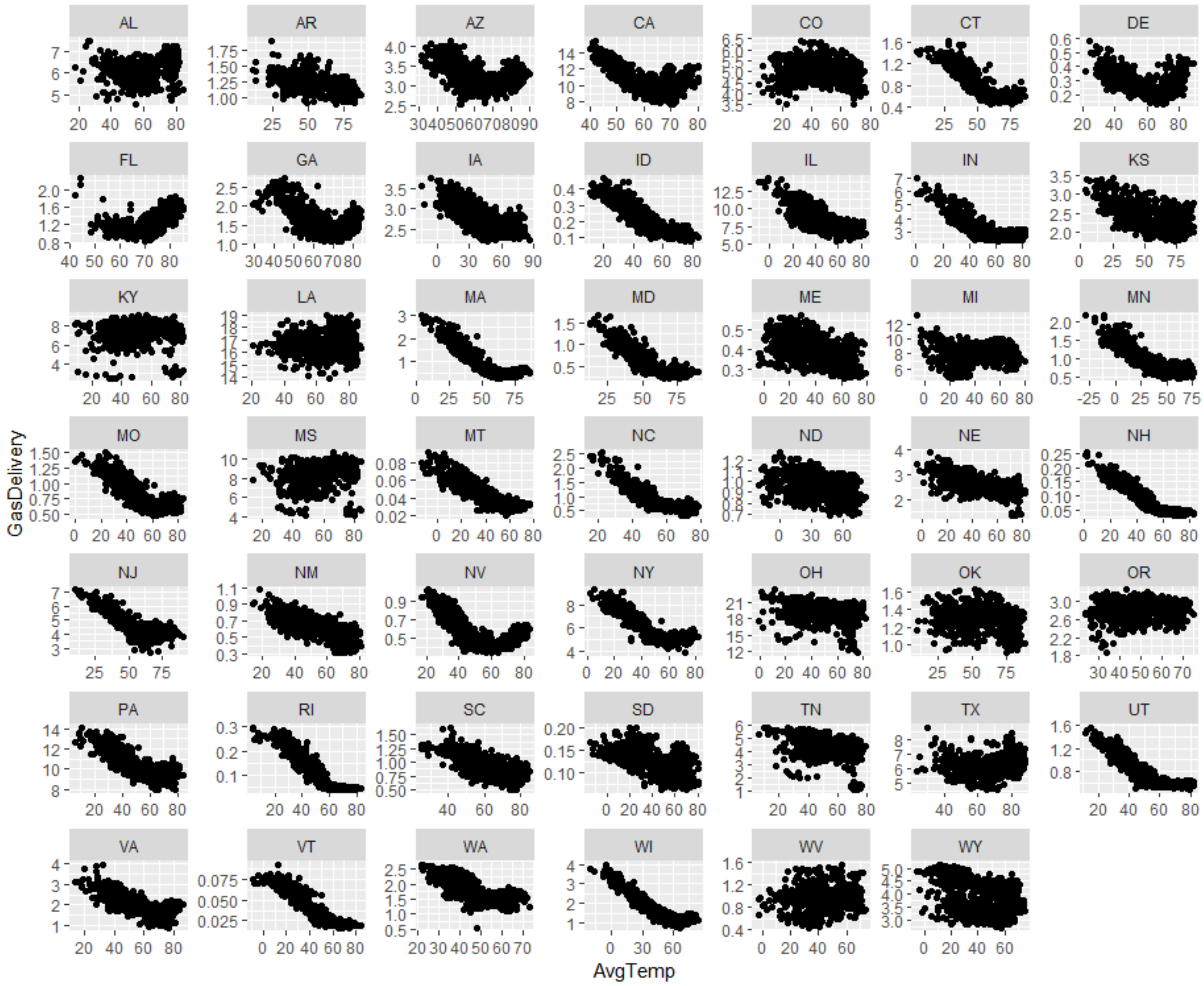

Figure 4-19. Correlated State and Regional Natural Gas Demand to Weather Variables.

Figure 4-19 clearly shows that daily gas consumption always changes conversely against temperature (except for a few states such as Colorado, Kentucky, etc.). At high temperatures, gas demand remains at a relatively low level. As the temperature decreases and the weather becomes colder, the gas consumption begins to rise continuously and reaches a peak.

A linear regression technique was applied as it could directly present the correlation between gas consumption and temperature with a numerical index. Such index can simply reflect the level of how load corresponds to the temperature change. Linear regression is widely used to analyze the relationship between two quantitative variables by measuring two discriminative coefficients: correlation coefficient rxy and coefficient of determination R2.

Relatively low coefficients of determination R2 were computed for the PJM states of Kentucky, Ohio, Tennessee, West Virginia in **Figure 4-19**. Additional gas demand and temperature data is being collected from recent gas pipeline nomination data.

Daily gas demand as a function of temperature (T) for each state was computed using second-order correlations (Gas demand = a+bT+cT2) as shown in **Figure 4-20**.

The conclusions that can be drawn from the correlations variables in **Figure 4-20** are the highest daily gas demand is consistent with population and intensity of winter conditions (as seen in the lowest value of intercept for smaller states such as Rhode Island and Vermont); low R2 values are computed for states with relatively high interconnection deliveries (e.g., Colorado, Louisiana, Michigan, Texas, etc.) while high R2 values are computed for states with low interconnection deliveries (e.g., New Hampshire and Wisconsin). For states such as Colorado, Louisiana, Michigan, and Texas, a significant portion of interconnection deliveries are exported to other neighboring states and not necessarily consumed within the state which results in a low correlation with the daily state-average temperature.

State	Intercept	Avgtemp	AvgTemp^2	Adjusted R-squared	State	Intercept	Avgtemp	AvgTemp^2	Adjusted R-squared
AL	8.0E+00	-7.6E-02	7.3E-04	0.16	NC	3.9E+00	-9.1E-02	6.2E-04	0.86
AR	1.4E+00	-1.2E-03	-2.7E-05	0.28	ND	1.0E+00	6.3E-05	-2.6E-05	0.14
AZ	6.4E+00	-9.4E-02	6.7E-04	0.36	NE	3.2E+00	-1.4E-02	2.4E-05	0.45
CA	4.6E+01	-1.1E+00	8.4E-03	0.68	NH	2.7E-01	-5.4E-03	3.0E-05	0.92
CO	4.2E+00	4.1E-02	-5.0E-04	0.10	NJ	9.4E+00	-1.4E-01	9.3E-04	0.77
CT	2.0E+00	-3.2E-02	1.7E-04	0.81	NM	9.7E-01	-6.1E-03	-8.8E-06	0.61
DE	9.5E-01	-2.3E-02	1.9E-04	0.39	NV	1.8E+00	-4.4E-02	3.6E-04	0.78
FL	7.1E+00	-1.9E-01	1.5E-03	0.64	NY	1.1E+01	-1.6E-01	1.1E-03	0.85
GA	6.0E+00	-1.3E-01	9.3E-04	0.49	OH	2.1E+01	-4.1E-02	2.1E-04	0.05
IA	3.4E+00	-2.2E-02	1.3E-04	0.57	OK	1.2E+00	5.6E-03	-7.0E-05	0.12
ID	5.7E-01	-1.0E-02	5.5E-05	0.85	OR	2.3E+00	2.0E-02	-1.9E-04	0.02
IL	1.3E+01	-1.5E-01	1.1E-03	0.58	PA	1.6E+01	-1.6E-01	9.7E-04	0.72
IN	7.1E+00	-1.2E-01	9.0E-04	0.79	RI	4.0E-01	-7.5E-03	3.5E-05	0.89
KS	3.4E+00	-2.8E-02	1.6E-04	0.45	SC	2.2E+00	-3.2E-02	1.9E-04	0.51
KY	5.5E+00	6.7E-02	-6.1E-04	0.02	SD	1.5E-01	-7.1E-04	-5.3E-07	0.35
LA	1.7E+01	-1.3E-02	1.4E-04	0.00	TN	5.1E+00	-1.9E-02	2.8E-05	0.09
MA	3.9E+00	-8.9E-02	5.8E-04	0.89	TX	9.9E+00	-1.3E-01	1.2E-03	0.20
MD	2.4E+00	-4.9E-02	2.9E-04	0.86	UT	2.1E+00	-4.0E-02	2.7E-04	0.90
ME	4.4E-01	-2.5E-04	-2.0E-05	0.26	VA	4.7E+00	-7.8E-02	5.1E-04	0.58
MI	8.5E+00	-4.3E-02	5.9E-04	0.03	VT	8.6E-02	-1.3E-03	4.4E-06	0.89
MN	1.5E+00	-2.5E-02	2.0E-04	0.78	WA	4.1E+00	-7.7E-02	5.4E-04	0.66
MO	1.7E+00	-2.8E-02	1.8E-04	0.75	WI	3.4E+00	-5.7E-02	3.6E-04	0.91
MS	6.1E+00	6.5E-02	-4.3E-04	0.04	WV	8.1E-01	5.0E-03	-3.5E-05	0.02
MT	7.3E-02	-9.4E-04	4.2E-06	0.80	WY	4.8E+00	-3.5E-02	2.7E-04	0.18

Figure 4-20. Correlation of Daily Gas Demand with Temperature by State

4.4 Impact of winter storm on natural gas and bulk power system in extended PJM

The team has formulated the impact of winter storm on forced outage rate of generators. The impact of cold weather on forced outage rate of transmission lines was also analyzed. In addition, for the winter seasons, the winter weather parameter (WWP) is used as the weather parameter to analyze the impact of cold weather on electric demand. Regarding the natural gas system, the impact of air temperature on gas demand was investigated. The impacts of extreme cold weather on natural gas pipeline operations and gas production were also studied. Details of the model development procedure are presented in this section.

4.4.1 Findings, Decisions and Conclusion

Through the abovementioned tasks, the team could provide the following findings, and conclusions:

1. The extremely cold weather will result in high generator outage rate. According to the outage data from Generating Availability Data System (GADS), the historical winter monthly data during 2009-2014 in the extended PJM area shows that the Equivalent Forced Outage Rate (EFOR) performance of coal units ranged from 4.9% to 14.2%; the winter monthly EFOR of natural gas units ranged from 4.8% to 25.5%; the winter monthly EFOR of nuclear units ranged from 0% to 4.7%; the winter monthly EFOR of hydro/pumped storage units ranged from 0.9% to 10.4%.

2. The team investigated the impact of weather conditions on transmission line outage rate and collected the element outage frequency, element outage duration, repair time, and up time for different voltage levels of transmission lines in the extended PJM area.

3. The team modeled the impact of temperature and wind speed on load during *winter*. The relationship between WWP and winter load is analyzed. We found that the correlations between WWP and load is very strong. When the WWP value is greater than 40, there appears to be minimal load response to weather conditions.

4. The team investigated whether dependence of daily natural gas demand with temperature may differ from State-averaged and LDC-averaged results. The assumption was the temperature dependence for LDCs would essentially match those for the entire State. Spot checks show this assumption is generally valid with some degree of deviation.

5. Extreme cold weather has a negative impact on gas pipeline equipment. The historical results indicate that the primary effect of extreme cold generally is the disruption of operations of one to two natural gas compressor stations located within the cold weather envelope. Another impact on pipelines is frost heave of the ground resulting in pipeline deformation, but the DOT data indicates that pipeline breaks occur at a much lower rate.

6. Extreme cold weather can result in water produced together with natural gas forming ice-like hydrates that plug the valves coming out of gas wellheads (called well "freeze-off"). Daily natural gas production was dependent on the previous day minimum temperature (which seems reasonable since today's gas production will depend on how cold was the previous day). Extreme cold weather impacts on natural gas production were investigated and possible constraints of on-site desiccant storage to continued gas production supply. Algorithms were developed correlating current day natural gas production with the previous day minimum temperature for individual counties in Ohio, Pennsylvania, and West Virginia.

4.4.2 Impact of winter storm on forced outage rate (FOR) of generators

The extreme weather will largely affect the outage rate of generators. For instance, from frozen natural gas wells to frozen wind turbines, all sources of power generation face difficulties during the winter storm. The team collected the historical equivalent FOR (EFOR) data [67] of generators in PJM area, as shown in **Figure 4-21**

Figure 4-21. The EFOR value is defined by the following equation:

$$EFOR = \frac{FOH + EFDH}{FOH + SH + EFDHRS} \times 100\%$$

where, Forced Outage Hours (FOH) is the forced outage hours, SH is the service hours, EFDH is the equivalent forced derated hours, Equivalent Forced Derated Hours during Reserve Shutdown (EFDHRS) is the equivalent forced derated hours during reserve shutdowns. The forced outage rate of generators during winter storm and summer drought period increased significantly, as shown in **Figure 4-22**. According to the outage data from Generating Availability Data System (GADS), the historical winter monthly data during 2009-2014 in the extended PJM area shows that the Equivalent Forced Outage Rate (EFOR) performance of coal units ranged from 4.9% to 14.2%; the winter monthly EFOR of natural gas units ranged from 4.8% to 25.5%; the winter monthly EFOR of nuclear units ranged from 0% to 4.7%; the winter monthly EFOR of hydro/pumped storage units ranged from 0.9% to 10.4%.

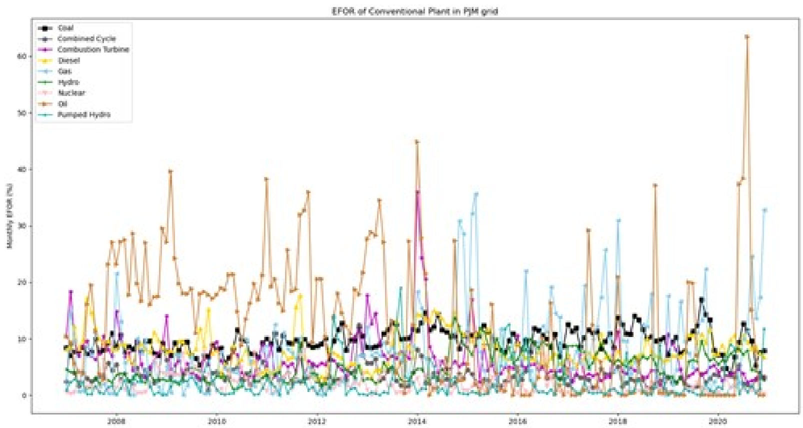

Figure 4-21. Historical FOR data of different type of generators in PJM area

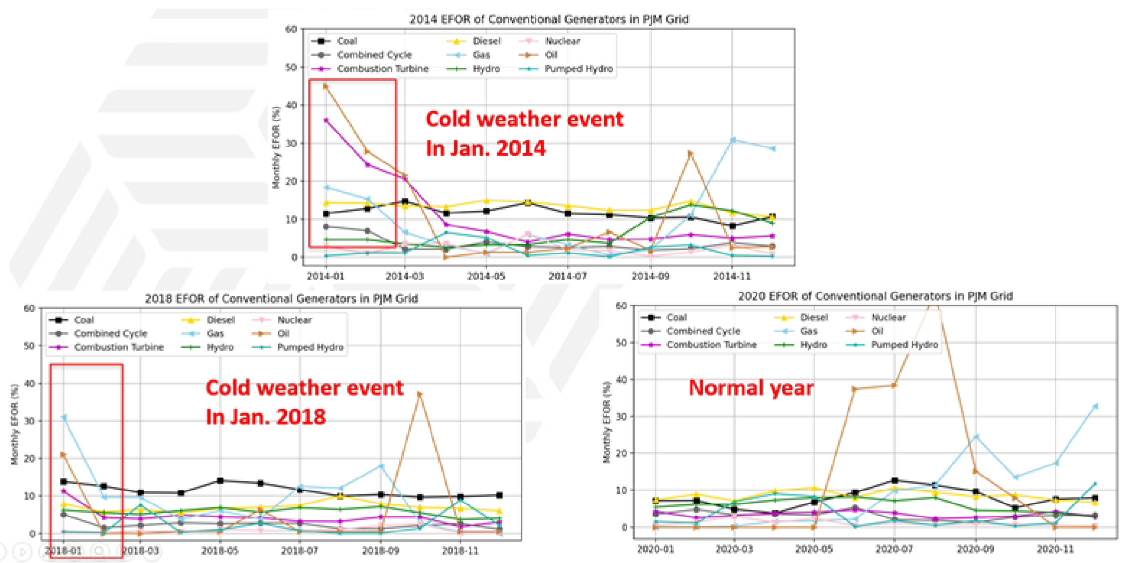

Figure 4-22. EFOR data of generators in PJM area during summer drought and winter storm events

Based on the data shown in

Figure 4-21 and **Figure 4-22**, it can be found that:

- The outage rates of oil units, combustion turbine, and gas steam units are relatively high than other units.
- Nuclear, combined cycle, and hydro units have a relatively lower outage rate than other units.
- In winter seasons, the outage rate of units is higher than other time.

4.4.3 FOR of transmission lines

NERC has been collecting continent-wide transmission inventory and outage data (see **Figure 4-23**) that comprise. The team checked the outage metrics information provided at NERC website, and collected element outage frequency, element outage duration, repair time, and up time for different voltage level of transmission lines in extended PJM area from 2011 to 2020.

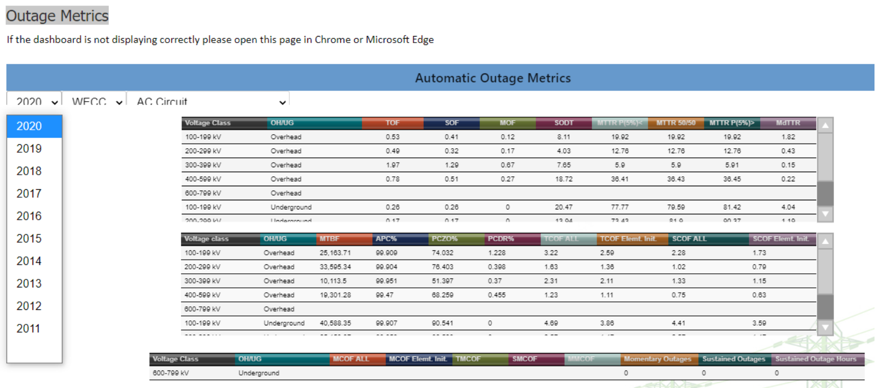

Figure 4-23. Outage data of transmission lines provided by NERC

4.4.4 Impact of winter storm on electric load

To model the impact of hot weather on electric load, the team collected the historical load data and weather data of PJM area during winter (Jan., Nov., and Dec.). Firstly, we calculated the WWP value using the following equation [68]:

$$\begin{cases} WWP = Temp - \left(0.5\ \times (Wind - 10)\right), if\ Wind > 10 \\ WWP = Temp, if\ Wind\ \leq 10 \end{cases}$$

where, Wind = Wind velocity in MPH, Temp = Dry bulb temperature. For each load zone, we used linear spline fitting functions to map the relationship between WWP and electric load. The relationships between WWP and load of AE, Dayton, and COMED zones are shown in

Figure 4-24. With the decrease of WWP value, the daily maximum load increases. At WWP values greater than 40, there appears to be minimal load response to weather conditions.

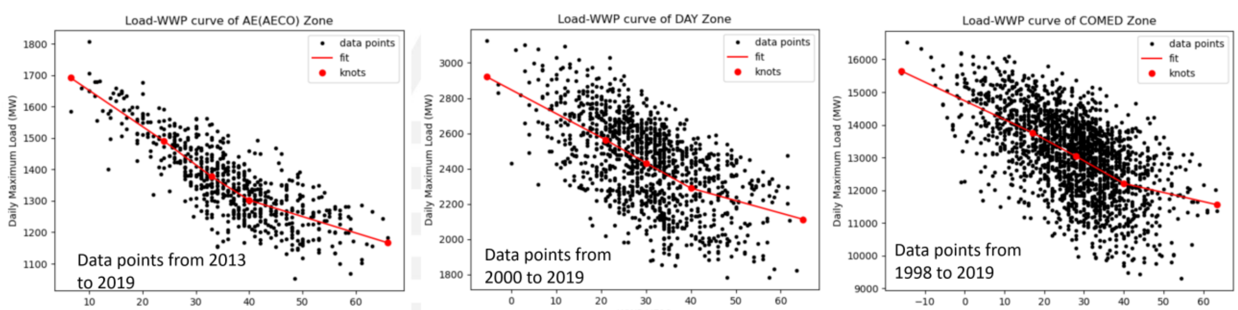

Figure 4-24. The impact of WWP parameter on load of AE, Dayton, and COMED

4.4.5 Impact of winter storm on natural gas demand

The extreme winter event gas demand profile was established based on the assumed historical weather conditions and correlations of gas load versus temperature/weather variables, with correlations developed for all Lower 48 States (see Task 4.3.7). This analysis investigated whether dependence of daily natural gas demand with temperature may differ from State-averaged and LDC-averaged results. The assumption was the temperature dependence for LDCs would essentially match those for the entire State. Spot checks show this assumption is generally valid with some degree of deviation. **Figure 4-25** shows an example comparison between Pennsylvania and Columbia Gas of Pennsylvania, which serves approximately 440,000 customers in in 450 communities in 26 counties throughout Pennsylvania.

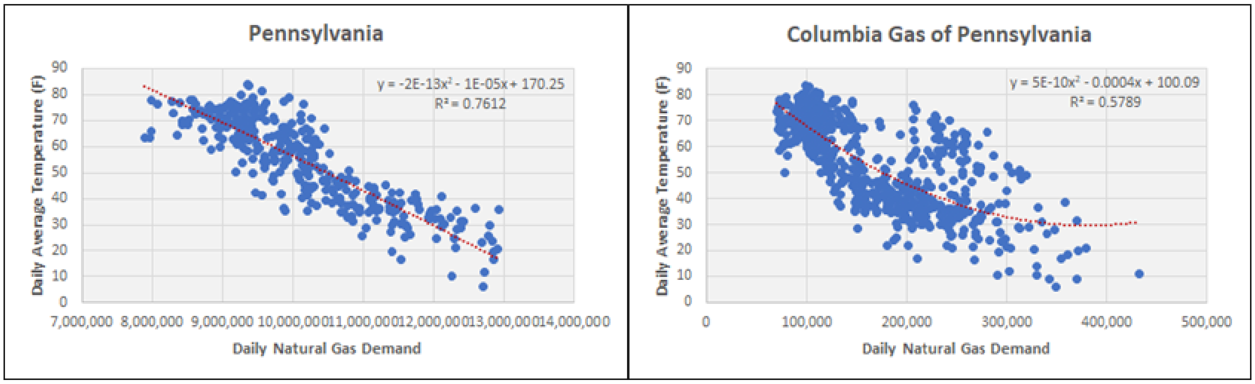

Figure 4-25. Comparison of Natural Gas Demand as a Function of Temperature between Pennsylvania and Columbia Gas of Pennsylvania

4.4.6 Impact of winter storm on pipeline operations

One of the largest issues that can impact gas-fired generation during extreme winter events is the curtailment of pipeline operations or interruption of fuel supply. As natural gas is widely used outside the power sector, the demand from other sectors—in particular residential heating demand during cold winter weather—can significantly affect the ability of pipeline operators and suppliers to deliver natural gas to the power sector.

Extreme cold weather can also have a major impact on gas pipeline equipment. With exposure to cold weather, the pipeline system can be threatened by a number of circumstances that can cause failure in components. Some of these include frost heave, loads on pipeline components due to snow and ice accumulation, thermal stresses due to extreme cold temperatures, and confined expansion of freezing water within components.

Historical extreme cold weather impacts on natural gas pipeline operations were investigated using DOT incident data submitted to PHMSA by pipeline operators since 1970 [79]. These historical results indicate that the primary effect of extreme cold generally is the disruption of operations of one to two natural gas compressor stations located within the cold weather envelope (**Table 4-2**). Another impact on pipelines is frost heave of the ground resulting in pipeline deformation, but the DOT data indicates that pipeline breaks occur at a much lower rate.

Table 4-2. Extreme Cold Weather Impacts on NG Pipeline Operations using DOT Incident Data

DOT Pipeline Incident on Extreme Cold Impacts (2010 to present)															
Month-Year	Number Incidents	Failure Location		State											Outside Temp (F)
		Compressor Station	Pipeline	CO	IL	MA	MI	MS	ND	NE	OK	TN	TX	WY	
Feb-21	5	2	3							1	1		2	1	
Nov-19	1	1										1			
Jan-18	2	2													
Jan-17	2	2										1		1	
Dec-16	1	1		1											-15
Feb-15	2	2				1		1							
Feb-14	2	2			1		1								
Dec-13	1	1							1						-30
Feb-11	1	1													
Jan-11	2	1	1										1		
Feb-10	1		1								1				
Total	20	15	5	1	1	1	1	1	1	1	2	2	3	2	

The NTRR analysis assumed the disruption of two compressor stations located in the area of the most extreme cold temperatures and determine impacts to downstream natural gas deliverability. Within the PJM/SERC service territory, the historical coldest region during December 1989 was located in western Ohio/eastern Pennsylvania, as shown in **Figure 4-26** (for December 18, 1989, [80]).

Figure 4-26. Daily Highest and Lowest Temperatures during December 18, 1989

Western Ohio/eastern Pennsylvania contains many gas compressor stations that could be at-risk of extreme weather conditions. **Table 4-3** was be used to determine the two compressor stations subject to an outage as a result of the extreme winter event; the facilities in **Table 4-3** had suffered recent outages and would be candidates for a shutdown due to the winter storm.

Table 4-3. Natural Gas Compressor Stations Which Experienced a Recent Outage Incident Reported to DOT (2010-Present)

Pipeline Name	Facility Name	State
Columbia Gas Transmission	Brinker Compressor Station	OH
Columbia Gas Transmission	Pavonia Compressor Station	OH
Columbia Gas Transmission	Artemas Compressor Station	PA
Columbia Gas Transmission	Lucas Compressor Station	OH
Columbia Gas Transmission	SR-696	OH
Columbia Gas Transmission	Eagle Compressor Station	PA
Dominion Transmission, Inc	Chambersburg Compressor Station	PA
National Fuel Gas Supply Corp	Ellisburg Compressor Station	PA
Rockies Express Pipeline LLC	Columbus Compressor Station	OH
Rover Pipeline, LLC	Defiance CS	OH
Rover Pipeline, LLC	Rover Mainline	OH
Tennessee Gas Pipeline Co	Compressor Station 209	OH
Tennessee Gas Pipeline Co	TGP Station 315 (Wellsboro CS)	PA
Texas Eastern Transmission, LP	Marietta Compressor Station	PA
Texas Eastern Transmission, LP	Wheelersburg Ohio Compressor Station	OH
Texas Eastern Transmission, LP	Line 19	PA
Transcontinental Gas Pipe Line Co	Station 520	PA
Transcontinental Gas Pipe Line Co	Station 535	PA

A physical disruption to a compressor station can interrupt the flow of gas or reduce pressure to multiple electric generating units. The reduction in downstream compressor station deliverability would be determined using the compressor power equation:

$$\frac{BHP}{stage} = 3.03 \cdot Z_{avg} \cdot \left[\frac{Q_g T_s}{E}\right] \cdot \left(\frac{k}{(k-1)}\right) \cdot \left(\frac{P_L}{T_L}\right) \cdot \left[\left(\frac{P_d}{P_s}\right)^{\left(\frac{(k-1)}{k}\right)} - 1\right]$$

BHP = *brake horsepower*

Q_g = *gas flow rate, MMSCFD*

T_s = *suction temperature, °R*

Z_{avg} = average compressibility factor, $\frac{(Z_s - Z_d)}{2}$

Z_s = *suction compressibility factor*

Z_d = *discharge compressibility factor*

E = *overall efficiency:* *Low speed reciprocating units – 0.85*; *High speed reciprocating units – 0.82*

k = *ratio of specific heats,* C_p/C_v

C_p = *specific heat at constant pressure,* $Btu\ (lb \cdot °F)$

C_v = *specific heat at constant volume,* $Btu\ (lb \cdot °F)$

P_s = *suction pressure, psia*

P_d = *discharge pressure, psia*

P_L = *standard pressure, psia*

T_L = *standard temperature,* $°R$

As an example,

Figure 4-27 provides a visual representation of a hypothetical pipeline that could be affected by the sudden failure of a single compressor station (all compressors and backup compressor) [81]. In this example, a compressor station failure at a downstream location would impact gas pressures and flows over a wide dispersion of generators as the downstream gas demand draws down pressure in the pipeline. For simplicity, only those power plants that are known to be natural gas only are considered impacted (dual-fuel units were excluded).

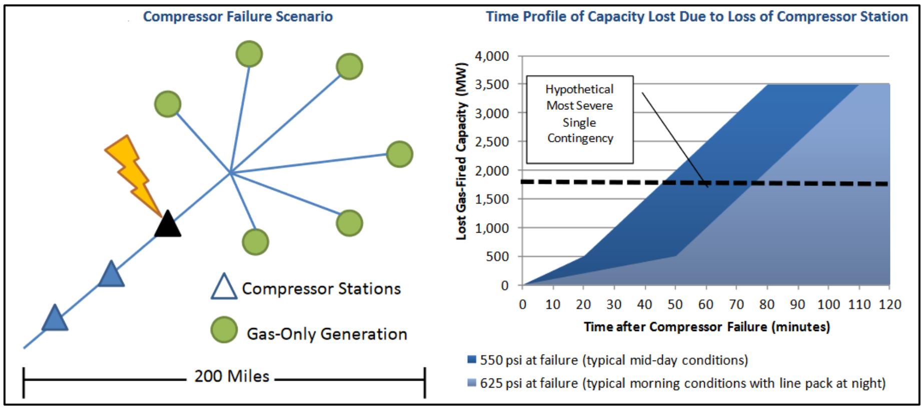

Figure 4-27. Assumed Compressor Station Failure and Impact on Gas-Fired Generation

The NTRR project would apply the approach outlined in the NERC report. However, it should be noted that disruptions to natural gas facilities can have varying impacts on the electric system depending on location due to differences in gas and electric infrastructure, generator location (direct connect or through LDCs), and availability of dual fuel.

4.4.7 Impact of winter storm on natural gas production

From 2007 to 2021, shale gas production in the U.S. increased by more than 1000 percent, according to the U.S. Energy Information Administration (**Figure 4-28**). Two of the largest shale reserves, Marcellus, and Utica, are located in the PJM region. The Marcellus Formation is the largest shale-sourced natural gas-producing formation in the United States and accounts for approximately 21% of all U.S. gross natural gas production [82]. This increased gas availability has driven down prices and made gas increasingly competitive with coal for power generation.

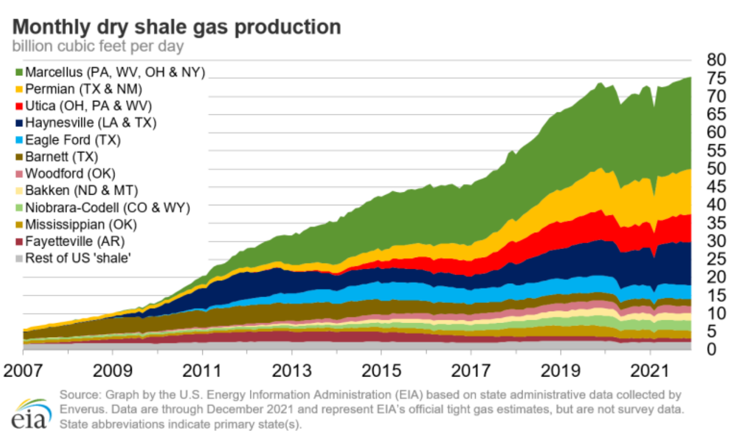

Figure 4-28. Monthly Dry Shale Production

In February 2021, an intense winter storm brought subzero temperatures to Texas and caused a nearly complete failure of the state's power grid. Initial media reports attributed the power grid failure to "wellhead freeze," or the freezing of natural gas wells.

While methane is the largest component of natural gas, other compounds, such as natural gas liquids (NGLs), carbon dioxide and water vapor, exist in natural gas as byproducts of its production. When the temperature drops sufficiently, the water produced alongside the natural gas can crystallize inside the pipeline, forming ice-like hydrates that plug the valves coming out of the wellheads. It is this phenomenon, not the actual freezing of wells, that is referred to as wellhead freeze. Production shut-ins are not uncommon in Texas during cold weather, typically occurring at least once or twice a year [83].

Historical gas production data was collected for the 2021 Texas Polar Vortex (see **Figure 4-29**). Well and processing plant freeze-ups were reported to have reduced natural gas production in Texas by more than 50% during the 2021 Texas Polar Vortex. The data in **Figure 4-29** indicates reduction in natural gas production was not limited only to Texas and that cold temperatures also impacted gas production in other Gulf Coast states. EBBdata was used to determine daily volumes of natural gas production as a function of State, county, and pipeline during this extreme weather event.

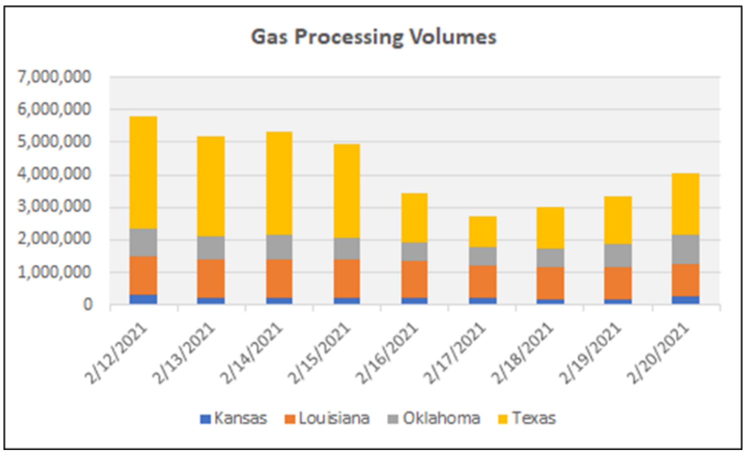

Figure 4-29. Daily Natural Gas Production Volumes during the 2021 Texas Polar Vortex

The EBB data was used to determine natural gas production as a function of county and state (partial sample in **Figure 4-30**). A three-color scheme was applied to identify highs and lows per county and state. As can be seen, there are multiple counties with zero daily gas production volumes and these zero values tend to occur between February 16 to 19.

County	State	2/12/2021	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	2/18/2021	2/19/2021	2/20/2021
CLARK	Kansas	248	248	248	248	0	196	0	290	290
GRANT	Kansas	229,666	221,433	208,995	199,109	188,934	181,663	170,639	153,292	190,132
LEAVENWORTH	Kansas	1,300	1,300	1,300	1,300	0	1	800	800	1,300
RENO	Kansas	10,937	532	3,501	1,801	1,801	4,031	4,362	3,801	14,269
SEWARD	Kansas	56,001	5,001	5,001	5,001	5,001	21,001	15,001	21,001	50,001
ACADIA	Louisiana	37,473	37,000	37,000	37,000	37,000	37,000	17,946	25,000	25,000
BOSSIER	Louisiana	80,720	65,645	65,645	65,645	54,345	70,838	21,990	19,850	33,831
CADDO	Louisiana	750	750	750	750	0	0	750	0	750
CALCASIEU	Louisiana	156	157	157	157	157	157	156	156	1
CAMERON	Louisiana	93,689	67,911	67,911	67,911	67,911	12	12	12	1,312
DE SOTO	Louisiana	32,508	32,508	32,508	32,508	32,508	10,143	143	10,144	10,143
EVANGELINE	Louisiana	850	850	850	850	850	0	0	0	900
LAFOURCHE	Louisiana	5,430	5,350	5,350	5,350	5,350	5,350	5,350	5,350	4,892
LINCOLN	Louisiana	10,475	12,175	11,575	11,575	11,575	11,575	31,593	21,001	21,501
LOUISIANA OFFSHORE	Louisiana	19,569	19,473	20,678	20,678	20,678	20,644	18,602	18,600	17,702
PLAQUEMINES	Louisiana	522,258	543,764	544,764	544,764	574,678	611,512	617,116	564,411	535,902
RED RIVER	Louisiana	13,560	13,560	13,560	13,560	13,560	0	0	0	0
ST MARTIN	Louisiana	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
ST MARY	Louisiana	308,456	329,578	340,342	326,462	279,628	173,617	180,610	262,818	315,732

Figure 4-30. Natural Gas Production during the 2021 Texas Polar Vortex as a Function of County and State

NOAA daily temperature data collected for the 2021 Texas Polar Vortex and daily gas production was normalized based on gas production on February 12, 2021. The normalized gas production was correlated against minimum daily temperature in the county and State (**Figure 4-31**). The results show no correlation between normalized gas production and minimum daily temperature.

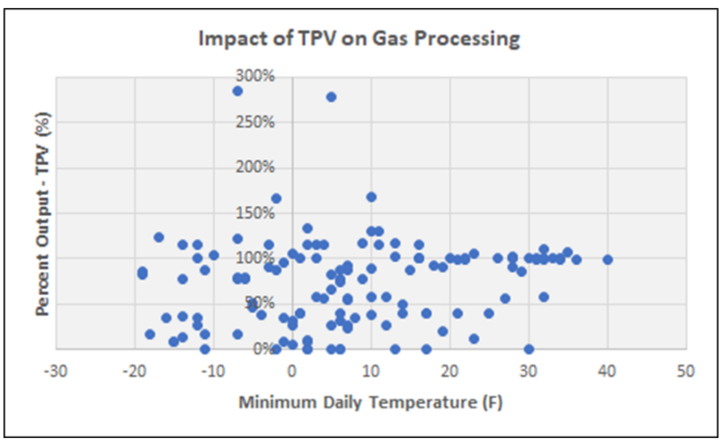

Figure 4-31. Natural Gas Production versus Minimum Daily Temperature for the 2021 Texas Polar Vortex

Further analysis showed that daily natural gas production was dependent on the previous day minimum temperature (which seems reasonable since today's gas production depends on how cold was the previous day). Extreme cold weather impacts on natural gas production were investigated (examples shown in **Figure 4-32**) and possible constraints of on-site desiccant storage to continued gas production supply. Algorithms were developed correlating current day natural gas production with the previous day minimum temperature for individual counties in Ohio, Pennsylvania, and West Virginia. Following agreement on the winter storm conditions, daily gas production was estimated for each affected county and the receipts to the interconnecting pipelines were determined assuming a normal dispersal pattern.

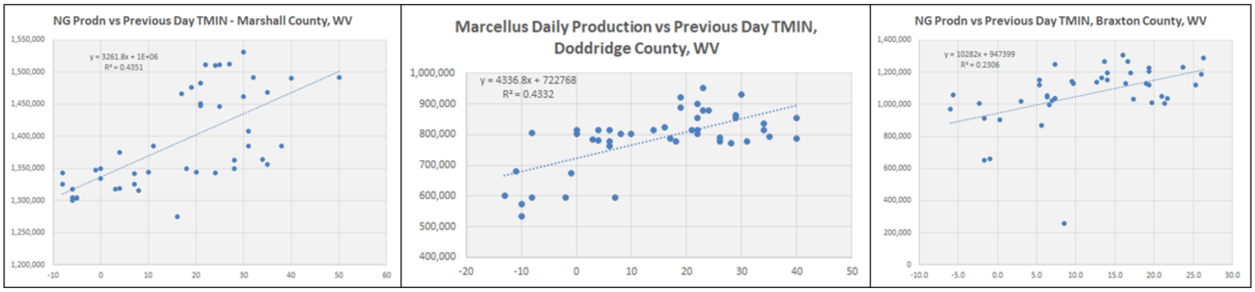

Figure 4-32. Example Extreme Cold Weather Impacts on Natural Gas Production

The available data shows that increased wet gas production has a higher likelihood of freeze-offs than dry gas production.

Natural gas nomination data was used in coordination with U.S. Environmental Protection Agency (EPA) gas-fired hourly generation data during the 2021 Texas Polar Vortex to identify dates when pipelines experienced reductions in gas supply and the degree of reduction (partial sample in **Figure 4-33**). EBB data was used to determine daily volumes of natural gas production as a function of State, county, and pipeline. Examples of interstate gas pipelines which experienced significant gas supply issues included Cameron Interstate Pipeline, El Paso Natural Gas, Enable Gas Transmission, and Gulf South Pipeline (see **Figure 4-33**).

pipeline_name	role_code	2/12/2021	2/13/2021	2/14/2021	2/15/2021	2/16/2021	2/17/2021	2/18/2021	2/19/2021	2/20/2021
American Midstream (MidLa) LLC	R	12,672	14,616	14,616	15,583	16,550	13,845	13,893	14,106	10,128
ANR Pipeline	R	1,064,481	973,511	945,840	905,644	865,907	519,351	772,348	973,400	1,297,062
Arkoma Connector Pipeline	R	240,361	221,682	223,736	208,592	168,284	134,407	131,027	143,250	215,041
Bobcat Gas Storage	R	73,779	183,530	137,822	115,258	162,556	199,789	222,311	157,129	66,929
Cameron Interstate Pipeline LLC	R	1,159,543	1,199,189	1,199,189	1,149,844	1,084,618	946,131	413,705	198,422	584,293
Columbia Gulf Transmission	R	278,898	265,219	253,762	258,592	346,789	469,216	236,702	212,419	155,711
Corpus Christi Pipeline	R	1,747,478	1,235,857	1,509,863	1,758,457	1,472,249	1,817,411	962,351	815,950	1,234,111
Creole Trail Pipeline	R	920,658	800,000	820,648	824,948	800,000	850,000	800,106	850,000	637,815
Crosstex LIG, LLC	R	185,876	196,276	196,276	196,276	103,276	99,176	98,238	98,487	104,987
Destin Pipeline Company LLC	R	274,492	273,289	273,889	273,889	273,811	250,123	209,707	237,721	242,804
Discovery Gas Transmission LLC	R	294,881	342,730	341,520	342,606	338,524	363,046	369,850	368,416	350,915
Egan	R	345,055	114,838	14,838	14,838	14,838	364,838	289,235	221,429	166,171
El Paso Natural Gas	R	1,669,597	1,610,798	1,725,200	1,420,487	870,680	330,177	408,541	833,959	978,248
Enable Gas Transmission (Centerpoint)	R	3,876,840	3,159,746	3,117,405	3,023,172	2,731,023	1,777,946	1,860,447	2,319,258	2,043,725
Florida Gas Transmission	R	1,135,445	1,028,666	1,008,562	1,051,336	940,236	805,472	903,449	958,119	1,081,022
Garden Banks Gas Pipeline, LLC	R	194,295	207,119	192,371	208,125	206,815	135,612	206,791	204,444	197,496
Golden Triangle Storage	R	115,177	118,916	118,916	88,916	118,916	0	200,300	100,301	19,485
Gulf Shore Energy Partners (FKA Dominion South)	R	21,158	14,583	14,583	14,583	14,583	0	0	0	0
Gulf South Pipeline Company LP	R	19,262,543	18,575,043	18,953,966	18,931,501	16,536,334	12,253,066	11,729,735	11,335,224	14,060,719

Figure 4-33. Daily Gas Supply Volumes for Gas Pipelines during the 2021 Texas Polar Vortex

Based on this, an approach was developed to predict impacts of polar vortex conditions on natural gas intrastate pipelines for which no EBB data is available. The extended PJM service territory contains intrastate pipelines such as Generation Pipeline LLC, Ameren Illinois, etc. and the following equation would be applied to determine the reduction in intrastate pipeline deliveries based on the interconnects between an intrastate pipeline and interstate pipelines:

$$[Reduction\ intrastate] = \sum_{k=1}^{n} [Reduction\ interstate\ "k"] * [Percent\ Total\ Receipts\ from\ “k”]$$

The cold weather event would reduce the amount of natural gas supply available for electric generation. The sum of pipeline receipts (after accounting for a drop in gas production due to low temperatures) would be compared with the estimated demand – broken down by customer class (residential-commercial, industrial, and electric power). If pipeline receipts are less than pipeline deliveries, curtailment of natural gas demand (load shedding) would result. The sequence of load shedding due to a natural gas supply shortfall is to proceed as follows: electric, industrial, commercial, and residential. Within each sector, interruptible loads would be shed first with firm loads to be shed last.

Data from the EIA Form 923 would be used to establish the natural gas supplier to each electric power plant and to identify which power plants could be affected by a disruption in natural gas supply. The EIA-923 data also establishes whether a gas-fired generator that is connected to a pipeline has a storage or asset management contract (and what type of contract). **Figure 4-34** provides a breakdown of gas supply and delivery contracts for gas-fired generators in PJM based on 2021 EIA data [57]. The majority of gas-fired electric generation in PJM had secured firm contracts for both supply and delivery, and these power plants would typically have a secure gas supply. In the event of a gas supply shortfall, gas-fired generators with an interruptible contract for supply and delivery would be curtailed first, followed by generators with a firm-interruptible contract.

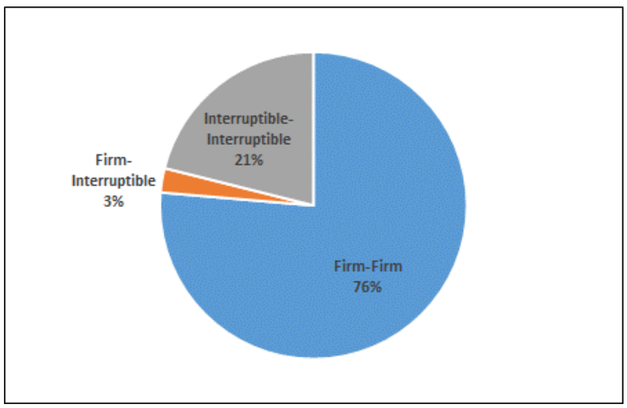

Figure 4-34. Breakdown of Gas Supply and Delivery Contracts for Gas-Fired Generators in PJM

Another factor concerning natural gas production which was considered was whether a 14-day cold spell would eventually deplete onsite storage desiccant storage volumes and result in major losses of natural gas production in the extended PJM service area. This activity is still under development.

In order to evaluate the increased number of forced outages and derates during periods of extreme weather, NERC Generating Availability Data System (GADS) data was collected for various generating unit types during a period of extreme weather and compared to data collected from the same period a year earlier when then weather was less extreme. For this preliminary evaluation, the SERC and NPCC regions were selected and the Jan 1-15, 2018 time period was selected as the extreme weather period. Data from the same days in 2017 was collected as the “normal weather period” for comparison. **Figure 4-35** shows the total number of forced outage and equivalent derate hours reported in the GADS database for the 2018 and 2017 periods.

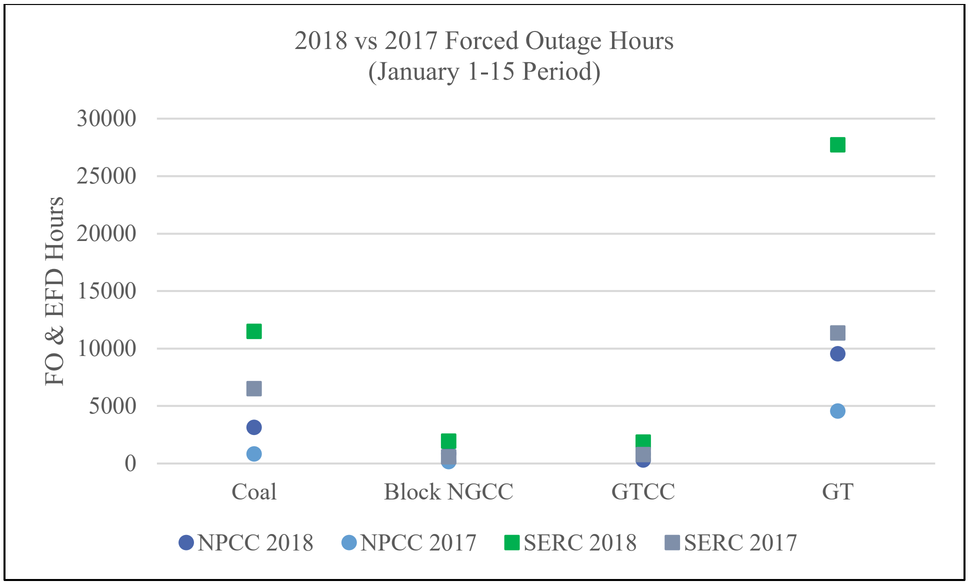

Figure 4-35. Total Number of Forced Outage and Equivalent Derate Hours Reported in the GADS Database for the 2018 and 2017 Periods.

As can be seen, there was significant increase in the forced outage and derate hours during the 2018 extreme weather event in both the NPCC and SERC regions. Coal and gas turbine units experienced more than double the amount of outage hours during the extreme weather event while combined cycle units also experienced increased outage rates.

The information in **Figure 4-35** can be used to predict the reduction in electric generation by technology type during the postulated extreme winter event.

4.5 Resource adequacy study

4.5.1 Findings, Decisions and Conclusion

Through the resource adequacy study, the team could provide the following findings, and conclusions:

1. According to the 2021 generation mix data of PJM/SERC, the team used the developed capacity derating models to calculate the capacity reduction of PJM/SERC grid. The team found that the maximum generation capacity reduction of conventional generators will reach 50 GW if the 2007 summer drought event strikes PJM/SERC region in near future. The capacity reduction data during the summer drought event can be found in **Figure 4-37** and **Figure 4-38**.
2. Worst-case snapshot: The usable capacity is 351.8GW – 50GW = 301.8 GW < 302.1 GW (extreme summer peak load), which means the generation capacity is less than extreme summer peak load. This leads to supply shortage.
3. As the 2025 extreme summer case was more constrained than the resource adequacy analysis results shown above, we expect even more supply shortage and more load interruption.

4.5.2 Extreme summer resource adequacy study

The team conducted the summer drought resource adequacy study for extended PJM power grid in near future based on:

- Extreme summer impact to 2021 generators (using 2007 summer drought data).

- 2021 summer peak load.
- No transmission impacts.
- No unit outages.
- Assume natural gas supply is sufficient during summer drought.

As the resource adequacy study was conducted based on the above assumptions, the conclusions obtained from this study were preliminary results. In 2021, the summer peak loads of PJM and SERC (exclude FL) area were about 150 GW and 135GW, respectively. The summer peak load of the PJM and SERC area will keep increasing in the following years, as shown in **Figure 4-36**. In addition, based on the peak load forecast report [58], the extreme summer peak loads are typically 6% higher than normal summer peak loads. Thus, if summer drought events hit PJM/SERC area in 2021, the extreme summer peak load should be 302.1 GW.

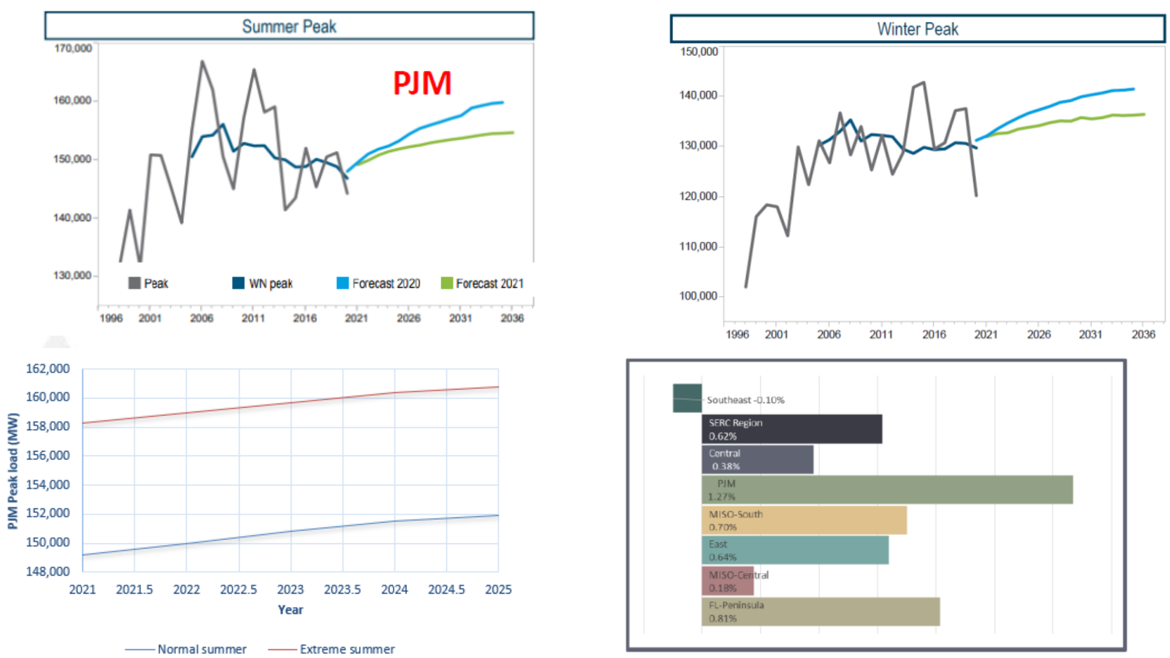

Figure 4-36. PJM and SERC load forecast

As of 2021, the projected resource capacity of PJM/SERC grid is about 362.6 GW, as shown in **Table 4-4** [10]. The projected on-peak resource capacity used in **Table 4-4** is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations). On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of renewable energy (such as wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Furthermore, if we consider the net firm transfers with neighboring areas, the projected resource capacity of PJM, SERC-E, SERC-C, and SERC-SE are 185.0 GW, 55.0 GW, 51.3 GW, and 60.5 GW, respectively [10]. Thus, the total projected resource capacity of 2021 PJM/SERC grid is 351.8 GW. Using the derating models mentioned in the previous sections, the team found that the maximum generation capacity reduction of conventional generators (exclude nuclear units) will reach 50 GW (see **Figure 4-38**) if the 2007 summer drought event strikes PJM/SERC region in near future. In specific, the capacity reduction of units with once through cooling systems and recirculating cooling systems will reach 50% and 10%, respectively. And the capacity reduction of combustion turbine will be about 14%, as shown in **Figure 4-37**. So, in the worst case, if the 2007 summer drought event hit the extended PJM area, the total usable capacity will be:

Total usable capacity $= 351.8\text{GW} - 50\text{GW} = \ 301.8\ \text{GW} < 302.1\ \text{GW}$ (Extreme summer peak load)

The result means the usable generation capacity is slightly lower than the extreme summer peak load. If forced outage events of generators are included in the above resource adequacy model, the available capacity of the extended PJM area will be further reduced. This will lead to more supply shortage. As the 2025 extreme summer case will be more constrained than the preliminary resource adequacy analysis shown above, we expect even more supply shortage and more load interruption.

Table 4-4. PJM/SERC fuel composition in 2021

Fuel Composition (2021)	PJM (MW)	SERC-E (MW)	SERC-C (MW)	SERC-SE (MW)
Coal	53,683	15,552	15,405	16,935
Petroleum	11,432	1,410	-	961
Natural Gas	82,519	18,467	21,475	30,250
Biomass	1,054	164	-	361
Solar	2,794	537	-	2,356
Wind	1,754	-	460	-
Conventional Hydro	3,072	3,133	4,155	3,288
Pumped Storage	5,229	3,174	1,769	1,632
Nuclear	32,626	12,104	8,618	5,818
Hybrid	7	-	-	-
Other	20	60	-	316
Total	**194,189**	**54,601**	**51,882**	**61,916**

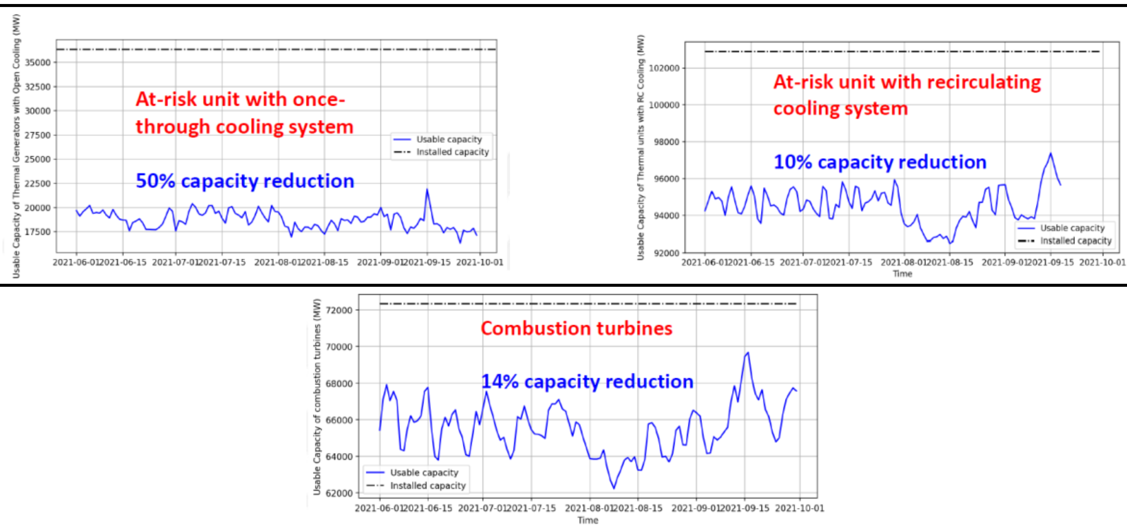

Figure 4-37. Total capacity reduction of at-risk thermal units with once-through cooling and recirculating cooling systems, and combustion turbines in PJM/SERC area (under 2007 summer drought condition)

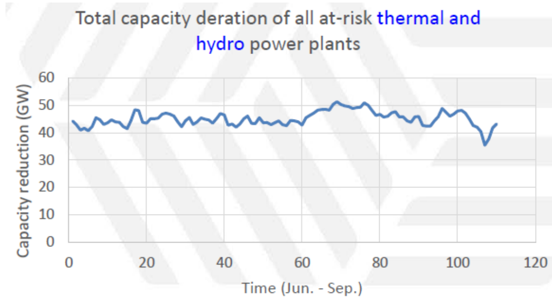

Figure 4-38. Total capacity reduction of all at-risk thermal units and hydro units in extended PJM area

4.6 Recommended further Study

For future work, the NTRR Team recommends the following areas for further study:

1) Near-term resilience and reliability assessment of extended PJM gas/electric system under extreme weather conditions

Study and analysis of the resilience and reliability assessment of extended PJM gas/electric system based on the work finished under this project should continue and include:

- Continue 2025 summer drought case development for extended PJM resilience study
- Develop 2025 winter storm case for extended PJM resilience study
- Model the impact of cyberattacks on PJM/SERC grid
- Coordinate with natural gas side (iteration between electric and gas side)

2) Near-term resilience and reliability assessment of ERCOT gas/electric system under extreme weather conditions

The objective of this study is to quantify the near-term resilience and reliability of the ERCOT gas/electric system under extreme weather events and provide recommendations for the decision-making of enhancing system resilience.

This assessment should implement resilience/reliability related studies based on the 2025 ERCOT synthetic model developed under NTRR Task 3, which incorporates generation additions and planned retirements by year 2025. The study should focus on the resilience and reliability evaluation of the ERCOT system under several credible extreme weather events in the near future. First, the impact of extreme winter storm and summer drought events on ERCOT power system should be formulated. Then, the impact models of extreme winter storm and summer drought events on natural gas systems of ERCOT region should be developed. The resilience and reliability of the gas/electric system should be quantified based on the results of the co-simulation of the ERCOT integrated gas and power system. Finally, recommendations should be proposed for the decision-making of enhancing ERCOT system resilience.

This additional analysis helps evaluate the resilience and reliability of the ERCOT gas/electric system under extreme events. By adopting bottom-up impact modeling approaches, the operational risks of the ERCOT system during extreme events in near-future could be precisely evaluated. The simulation results would benefit the stakeholders and help the ERCOT system better prepare for future extreme events. This work would provide recommendation for the policymakers and market to evaluate and enhance system resilience.

5. Task 5: Extreme Weather and Cyber in the West

5.1 Introduction

The focus of this task is the analysis of high-impact events on the 2025 WI power grid. Year one project efforts have been primarily preparatory, as full analysis depends on finalization and availability of the national base case models. Per initial project scoping, year 2 of phase 1 for the task 5 effort involved sensitivity analyses in the following dimensions: wildfire impact, natural gas price spike impacts, worst-case N-k continency impacts, and heat/drought impacts. The remainder of this section summarizes preparatory work and studies in support of the indicated year 2 sensitivity analyses. Other task 5 activity conducted relate to the exploration and development of "nomograms" (proxy constrains) for natural gas in the context of power grid commitment and dispatch models, as co-dispatch of power grid and natural gas systems is not presently technologically feasible. Given national base case model outputs related to gas supply, nomograms were implemented in the analysis of the WI 2025 case to represent realistic availabilities of natural gas fuel supplies.

5.2 Contingency Analyses, preparatory work, and studies

5.2.1 Wildfire Risk Analysis

Wildfire impacts are being considered on WI infrastructure, given recent historic events and projected intensification due to climate change. Wildfire data sources were secured via DOE's North American Energy Resilience (NAERM) model; LLNL leads integration and development of NAERM wildfire capabilities. Two key sources of wildfire data are available: (1) active wildfire perimeters for CONUS, obtained from the National Interagency Fire Center (NIFC); and (2) forecasted areas of wildfire ignition and spread within the state of California (www.pyrgence.org). Both the active and forecasted wildfire data were analyzed for the 2021 wildfire season, specifically focusing on bulk electric and natural gas infrastructure impacts.

An example of overlay of WI infrastructure from the 2021 Caldor wildfire (from last August 2021) is shown in **Figure 5-1**.

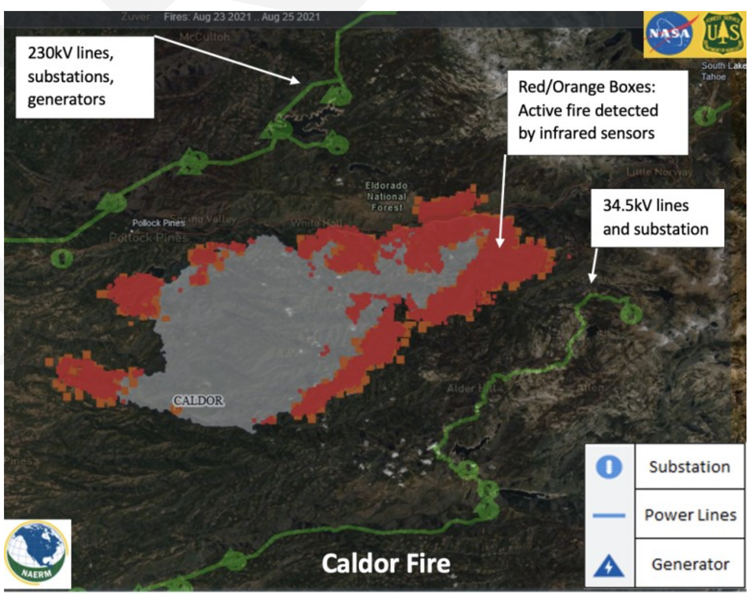

Figure 5-1. Overlay of WI infrastructure from the 2021 Caldor wildfire

An example of overlay of forecasted wildfire risk over the Sierra Nevada Mountain range in California in late August 2021 **Figure 5-2**, per the forecasted risk data from the Pyregence consortium (shown in the middle and right panels of the graphic), is as follows:

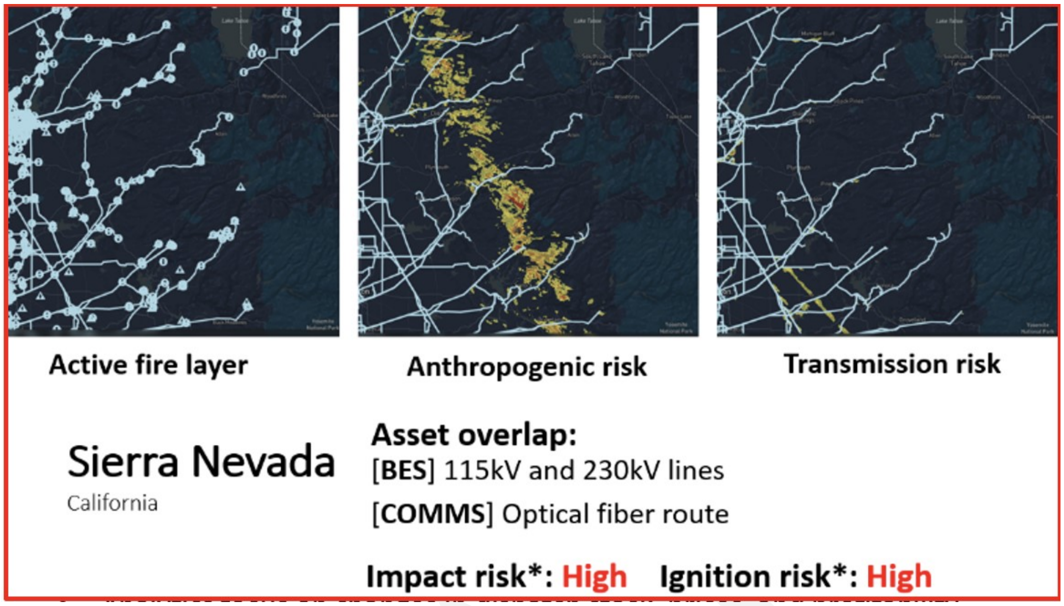

Figure 5-2. Overlay of forecasted wildfire risk over the Sierra Nevada Mountain range in California in late August 2021

Data overlays for WI 2025 models should be conducted as future analysis, to quantify impacts of likely outages due to wildfire activity in both California and the broader WI.

5.2.2 Natural Gas Price Spike Analysis

Either due to global events or market forces, the impact of natural gas price spikes on power system production and operations cost is of significant concern to both system operators and more broadly. Toward enabling such analyses on the WI, a study framework was developed for analyzing the impact of natural gas price spikes on resulting dispatch stacks. The experiments were conducted using the open-source Prescient PCM tool, available from: https://github.com/grid-parity-exchange/Prescient. The study was conducted on a high-share renewables PCM case known as RTS-GMLC, available from https://github.com/GridMod/RTS-GMLC and developed previously under DOE/GMLC funding. The analytic focus of this study was on changes in the dispatch stack, energy prices, and generator profitability.

We performed production cost simulation with three different NG prices for the base and modified RTS-GMLC test cases. In the modified case, the "start heat warm" and "start heat hot" parameter values are adjusted according to the "median start heat cold" values, per **Figure 5-3** (the changes reflect a more realistic thermal fleet):

Unit Type	MW Inj	Start Heat Cold (MMBtu), RTS-GMLC	Start Heat Warm (MMBtu), RTS-GMLC	Start Heat Hot (MMBtu), RTS-GMLC	Median Start Heat Cold (new)	Adjusted Start Heat Warm (new)	Adjusted Start Heat Hot (new)
Coal	76	5284.8	4861.4	3379.4	1080.2	993.7	690.7
Coal	155	10778.1	7437.5	6892.1	1057.3	729.6	676.1
Coal	350	17384.1	10114.4	9768.2	2661.5	1548.5	1495.5
Gas CC	297	7215.1	4536.1	3196.6	780.3	490.6	345.7
Gas CC	355	7215.1	4536.1	3196.6	869.4	546.6	385.2
Gas CT	22	1457.4	1122.5	452.8	42.8	33.0	13.3
Gas CT	44	1457.4	1122.5	452.8	30.9	23.8	9.6
Gas CT	55	1457.4	1122.5	452.8	34.9	26.9	10.8

Figure 5-3. production cost simulation (PCM) with three different natural gas (NG) prices

The three price levels that are used in simulations are **(1)** *default* ($3.8872/MMBtu), **(2)** *intermediate* ($13.13/MMBtu), and **(3)** *peak* ($23.86/MMBtu). **Figure 5-4** summarizes the results of the Prescient simulations for the three cases with peak natural gas prices.

CASE	Total demand	Total fixed costs	Total generation costs	Total costs	Total load shedding	Total renewables curtailment	Total on/offs	Total sum on/off ramps	Total sum nominal ramps	Maximum observed demand	Overall renewables penetration rate	Cumulative average price
Case 3(a)	618,394.27	4,599,739.87	1,229,483.53	5,829,223.40	1,505.96	62,524.18	435.00	5,646.00	22,477.12	4,485.32	62.73	9.43
Case 3(b)	619,989.68	6,767,962.08	3,359,645.87	10,127,607.95	37,407.52	2,949.26	456.00	6,633.45	19,355.13	4,718.98	43.27	16.34
Case 3(c)	629,697.56	8,325,048.75	3,416,334.34	11,741,383.09	45.75	26,718.56	573.00	5,160.00	24,527.88	4,699.98	42.53	18.65

Figure 5-4. Results of the Prescient simulations for the three cases with peak natural gas prices

In addition to standard PCM statistics, of significant interest to system operators is the nature of the dispatch stack. **Figure 5-5** shows the dispatch stacks under the three natural gas price scenarios.

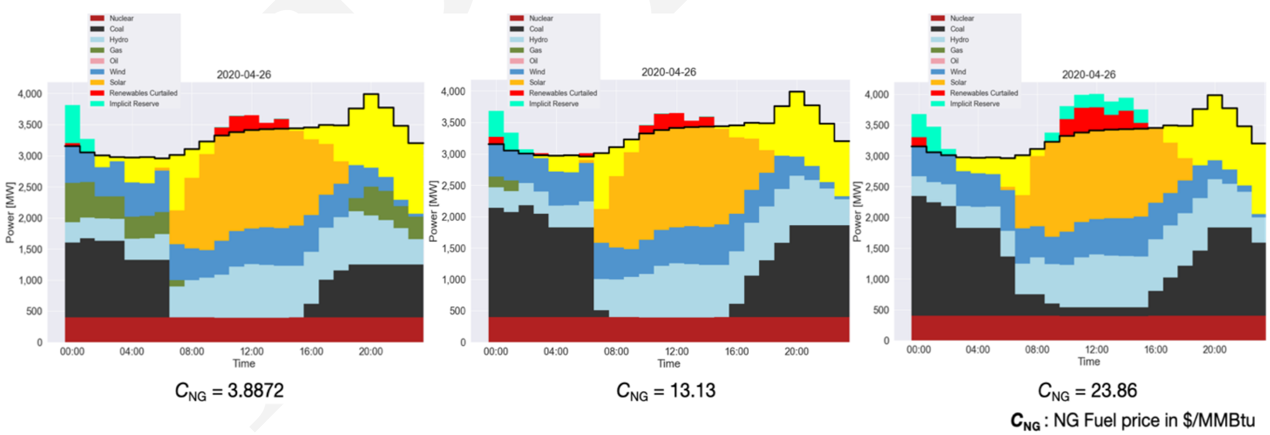

Figure 5-5. dispatch stacks under the three natural gas price scenarios

This particular day is known to be challenging from a reliability standpoint, which are accentuated by increases in natural gas prices – as slower-ramping units replace the more expensive faster-ramping units, reserve issues cause further reductions in load served. Further, renewables curtailment patterns shift, as do the on/off characteristics of coal units.

The impact of enhanced-realism parameters for thermal units in the RTS-GMLC case is significant, as shown in the **Figure 5-6** shows the dispatch stacks for the base RTS-GMLC case (left column) and enhanced RTS-GMLC case (right column), for both the default and peak natural gas price scenarios:

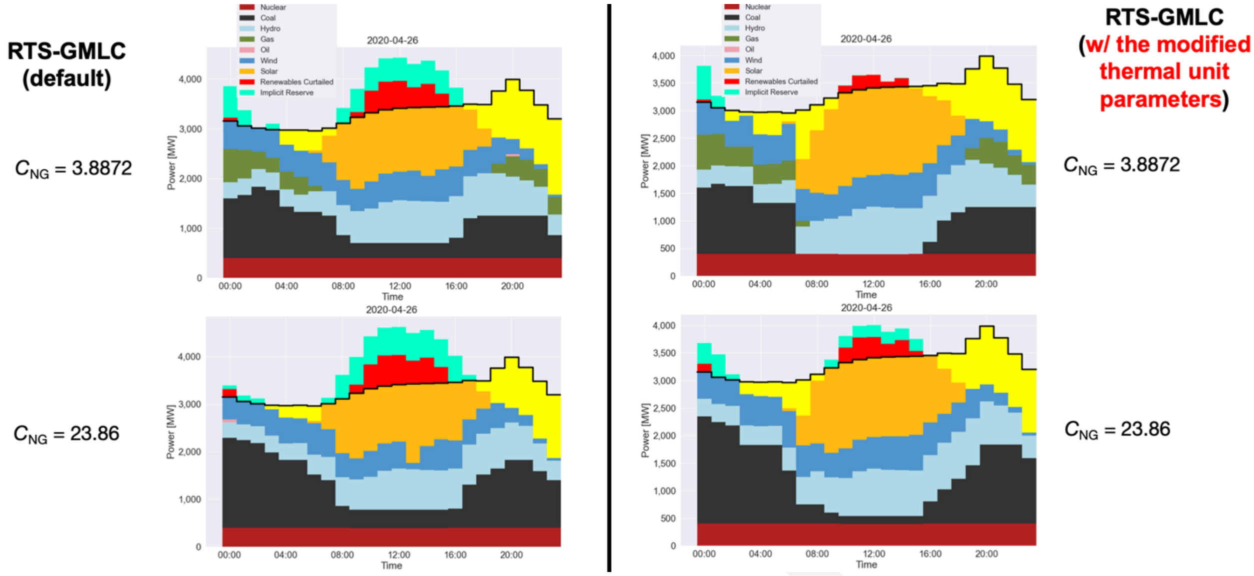

Figure 5-6. dispatch stacks for the base RTS-GMLC case (left column) and enhanced RTS-GMLC case (right column), for both the default and peak natural gas price scenarios

The RTS-GMLC natural gas price spike experiments described above provide the basis for a more comprehensive WI 2025 study, providing indications of the degree of change required to observe impacts and the level and type of impact that can be observed.

5.2.3 Worst-Case N-k Contingency Analysis

Worst-case N-k contingency analysis is being conducted to address "all-hazard" impacts associated with concurrent failures of multiple grid components, e.g., k >> 1. The source of component failures is intended to be agnostic to cause, e.g., cyber vs. physical and intentional vs. accidental/natural. Codes developed by LLNL for DOE's North American Energy Resilience Model (NAERM) effort, specifically the Intentional Threat Toolkit, were executed on WECC 2018 and 2020 planning cases, to identify high-impact contingencies for k ranging from 2 to 20. These contingencies were then simulated using transient power flow simulators, to determine cascading impacts and quantify overall impacts. Several severe events were identified starting with a contingency "budget" (the number of outaged components) of k=4, with impacts – quantified as both the load lost and number of subsequently outaged components) growing substantially with larger values. These initial experiments demonstrate that the worst-case N-k analytic capability implemented in the Intentional Threat Toolkit can be applied to WI-scale grid models, despite their significant computational challenge from the standpoint of optimization difficulty. Results for worst-case N-k contingencies that yield high impacts in the WI are necessarily sensitive, in that they identify critical grid component. Consequently, the details of the contingencies and the extent of the impacts are not reportable in an open forum. Analogous studies should be conducted for WI 2025 models with future analysis.

5.2.4 Drought and Heat Risk Analysis

Mirroring efforts conducted under task 4 for the EI, drought and heat analyses are a key sensitivity planned for WI analysis. To establish a process for analyzing and quantifying impacts on the WI due to drought and heat, sensitivity analyses were conducted using the GridView PCM tool, considering the WECC 2030 v2.0 case (obtained under standard NDA with WECC). Code infrastructure to support automatic updating of large numbers of line ratings were developed and tested. An illustrative result is obtained by de-rating by 15% (Rate A) all transmission lines in the CAISO region and simulating the WECC system via PCM analysis for a week in July. **Table 5-1** compares the results of the 48-h production cost model runs from the base and de-rated WECC cases:

Table 5-1. 48-h production cost model runs from the base and de-rated WECC cases comparison

	WECC 2030 v2.0 Base Case	WECC 2030 v2.0 Derating
Average LMP ($/MWh)	53.12	53.41
Average LMP Congestion ($/MWh)	14.48	14.85
Average LMP Losses ($/MWh)	2.46	2.39
Total Generation (MWh)	1,517,766.88	1,515,366.88
Total Load (MWh)	1,640,295.75	1,640,274.38
Total Served Load Including Losses (MWh)	1,693,410.75	1,693,427.75
Total Spillage (MWh)	1,223.44	2,540.66
Total Load Payment ($)	90,559,856.00	91,153,888.00
Total Generation Revenue ($)	74,811,896.00	74,955,376.00
Total Generation Cost ($)	34,131,908.00	34,167,556.00
Total Loss Demand Payment ($)	3,961,075.25	3,857,117.25
Total Congestion Supply Revenue ($)	18,839,330.00	19,137,536.00

Here, we see relatively minor impacts in terms of system reliability and costs, despite a modest reduction in overall transmission capacity limits.

6. References

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