NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Reliability and Security Technical Committee

Virtual Meeting via WebEx

June 9, 2021 | 1:00–4:30 p.m. Eastern

Attendee WebEx Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

1. **System Protection and Control Working Group (SPCWG) Scope Document* - Approve –** Jeff Iler, SPCWG Chair | Allen Schriver, Sponsor

   The SPCWG revised its scope document and is seeking approval.

2. **Probabilistic Assessments Working Group (PAWG) 2020 ProbA Scenario Case Study Report*– Approve -** Andreas Klaube, PAWG Chair | Kayla Messamore, Sponsor

   The NERC PAWG has responded to the RSTC and RAS comments on this study report. It combines all of the Assessment Areas' sensitivity results from the 2020 Probabilistic Assessment data and compares the results against the base case data. The NERC PAWG has obtained RAS approval and is seeking RSTC approval.

3. **PAWG Data Collections Technical Reference Document* – Approve -** Andreas Klaube, PAWG Chair | Kayla Messamore, Sponsor

   The NERC PAWG has responded to the RSTC on this technical report that discusses the various data sources available to a resource planner when performing probabilistic studies or assessments. The NERC PAWG has obtained RAS approval and is seeking RSTC approval.

4. **System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Reliability Guideline: UFLS Studies - Accept to Post for 45-day Comment Period -** Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The NERC SPIDERWG has developed a Reliability Guideline to provide guidance on impacts that higher penetration of DER may have on UFLS. The SPIDERWG requests authorization to post this Reliability Guideline for a 45-day industry comment period per the RSTC charter.

5. **SPIDERWG Presentation on the Modeling Survey – Information -** Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices. The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

2:30 P.M. - BREAK – 15 MINS

6. **Energy Reliability Assessments Task Force (ERATF) Update - Information –** Peter Brandien, ERATF Chair
   The ERATF will assess risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The ERATF serves the RSTC in providing a formal process to analyze and collaborate with stakeholders to address the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources whitepaper. This whitepaper identified energy availability concerns related to operations/operations planning and mid- to long-term planning horizons.

7. **Standing Committee Coordination Group (SCCG) Update* - Information –** Stephen Crutchfield, NERC Staff
   Per the SCCG scope document, the SCCG is to *"provide quarterly reports to the standing committees for inclusion in their public Agenda posting on cross-cutting initiatives addressing risks to the reliability, security, and resilience of the BPS. This report shall be prepared in advance and voted on by the SCCG at the SCCG's quarterly meetings."*

8. **Risk Registry – Information –** Soo Jin Kim, NERC Staff
   In an effort to continually monitor the existing risks to the bulk power system and manage the efforts of the ERO Enterprise to actively identify and address new threats, NERC will work with the SCCG to create a Risk Registry. This registry will overlap some with the risk profiles identified in the latest ERO Reliability Risk Priorities Report (RISC report), but the Risk Registry will focus on reporting current risks while the RISC report is a forward-looking view of the BPS. In an effort to ensure the risk registry captures the right categories of current risks, NERC is seeking feedback on the registry as it is developed.

9. **NERC Bylaw Changes – Information –** Lauren Perotti, NERC Staff
   On April 5, 2021, FERC approved a series of Bylaws revisions that were approved by the Board in August 2020. Among other changes, the revised Bylaws modified the Sector membership definitions to ensure consistency with the intent of fair and balanced participation in NERC governance by stakeholders with a significant role in the reliability and security of the bulk power system.

10. **Forum and Group Reports – Information**
    a. North American Generator Forum* – Allen Schriver
    b. North American Transmission Forum* – Roman Carter

11. RSTC 2020 Calendar Review – Stephen Crutchfield

2021 Meeting Dates	Time*	Location	Hotel
September 16, 2021 – Informational Session	2:00-4:00 p.m.	WebEx	None
September 22, 2021 September 23, 2021	Note Time Change: 11:00 a.m. to 4:30 p.m. 11:00 a.m. to 4:30 p.m.	WebEx	None
December 7, 2021 Informational Session	2:00-4:00 p.m.	WebEx	None
December 14, 2021 December 15, 2021	Please reserve entirety of both days	TBD	TBD

*All times are in Eastern.

12. Chair's Closing Remarks and Adjournment

*Background materials included.

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

System Protection and Control Working Group (SPCWG) Scope Document

Action
Approve

Summary
The SPCWG revised its scope document and is seeking approval.

System Protection and Control Working Group

Scope

Purpose

The purpose of the System Protection and Control Working Group (SPCWG), a working group of the Reliability and Security Technical Committee (RSTC), is to promote the reliable and efficient operation of the North American power system through technical excellence in protection and control system design, coordination, and practices.

Activities

1. Provide subject matter expertise for NERC Reliability Standards and technical guidelines, including, but not limited to, the following:
    a. Protection and control systems, including local and wide area applications, and ~~synchrophasor~~synchro phasor applications
    b. Remedial Action Scheme (RAS)
    c. Power system monitoring
2. Provide subject matter expertise upon request, on Protection System operations to the ERO Enterprise.
3. Provide technical support to the NERC Event Analysis Program, including input and development of any lessons learned as needed from the Event Analysis Subcommittee (EAS).
4. Provide technical support in the development of Implementation Guidance.
5. Serve as the liaison to the IEEE Power and Energy Society (PES) committees associated with system protection and their associated subcommittees and working groups, for collaborative promotion of technical excellence in system protection.
6. Develop and maintain a NERC technical reference library on system protection and control.
7. Other protection and control activities as determined by the SPCWG and approved by the RSTC.

Membership

The SPC~~S~~WG will generally follow the organizational structure of the RSTC with the following additions:

- Additional non-voting industry subject matter experts may be added as determined by the SPCWG
- Additional voting members who are industry subject matter experts may be added as determined by the SPCWG

A NERC staff member will be assigned as the non-voting Working Group Coordinator. The working group chair and vice chair are nominated by the SPCWG voting membership and approved by RSTC leadership for one, two-year term. The vice chair should be available to succeed to the chair.

Reporting

The SPCWG administratively reports to the RSTC ~~and liaisons to the Operating Committee (OC)~~ on pertinent technical issues.

Meetings

Four to six open meetings per year, or as needed. Emphasis will be given to conference calls and web- based meetings.

Document Development

Documents will be managed using the process described in the SPCWG Document Review and Approval Process.

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Probabilistic Assessments Working Group (PAWG) 2020 ProbA Scenario Case Study Report

Action
Approve

Summary
The NERC PAWG has responded to the RSTC and RAS comments on this study report. It combines all of the Assessment Areas' sensitivity results from the 2020 Probabilistic Assessment data and compares the results against the base case data. The NERC PAWG has obtained RAS approval and is seeking RSTC approval.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2020 Probabilistic Assessment

Regional Risk Scenario Sensitivity Case

June 2021

RELIABILITY | RESILIENCE | SECURITY




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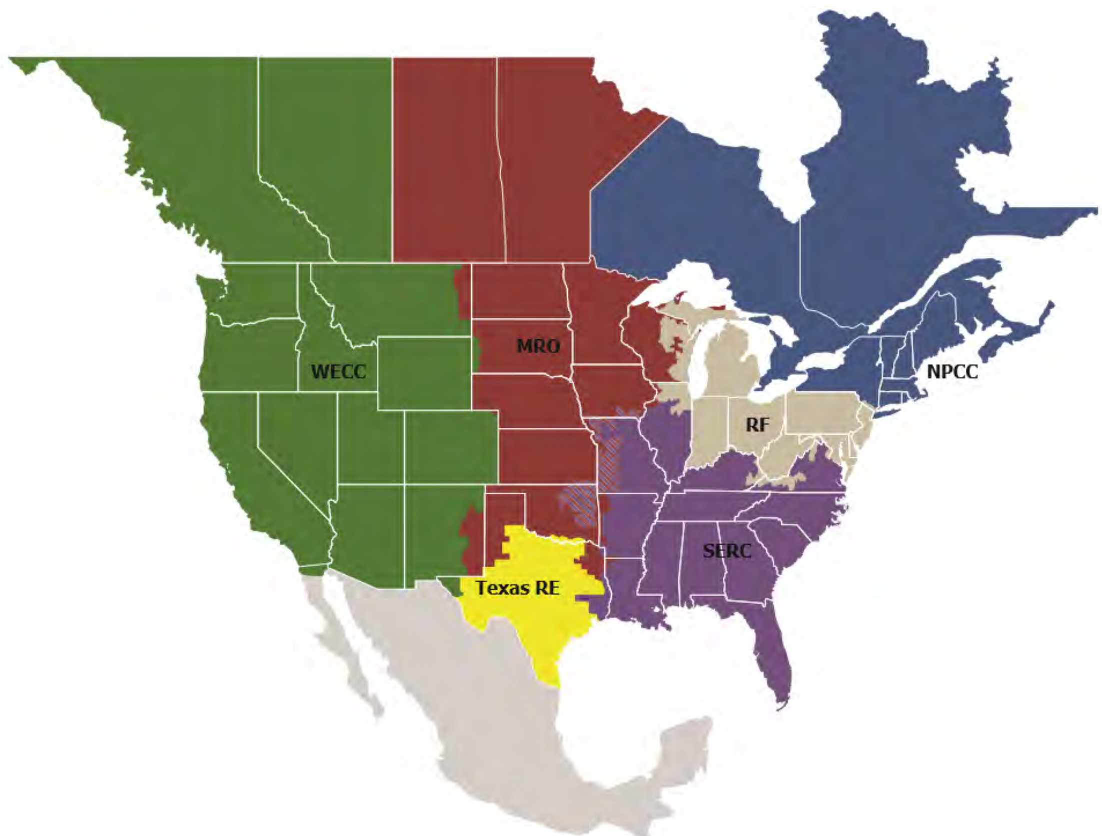
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council

FRCC

MRO – Midwest Reliability Organization

MRO-SaskPower
MRO-Manitoba Hydro
MISO

NPCC – Northeast Power Coordinating Council

NPCC-New England
NPCC-Maritimes
NPCC-New York
NPCC-Ontario
NPCC-Québec

RF – ReliabilityFirst

PJM

SERC – SERC Reliability Corporation

SERC-East
SERC-North
SERC-Southeast
SERC-FP

SPP RE – Southwest Power Pool Regional Entity

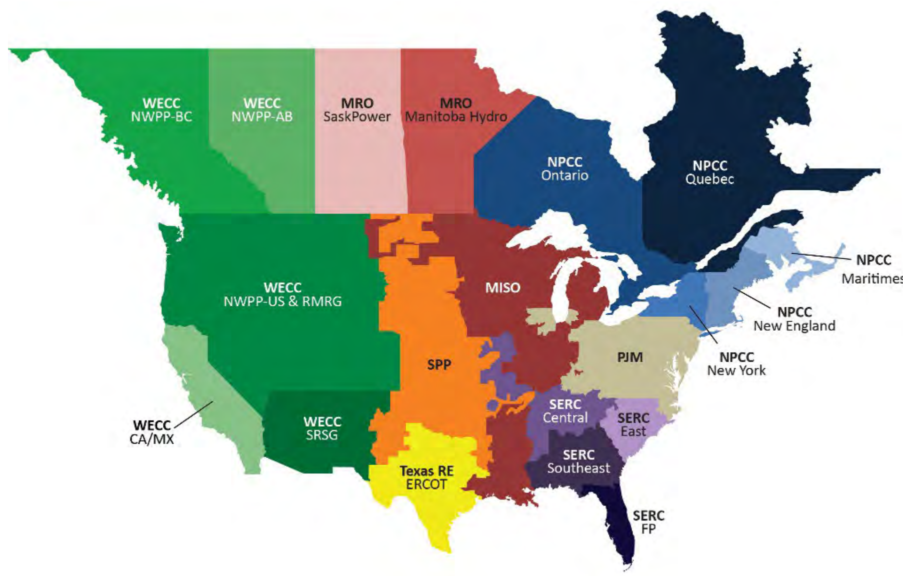
SPP

Texas RE – Texas Reliability Entity

Texas RE-ERCOT

WECC – Western Electricity Coordinating Council

WECC-BC
WECC-AB
WECC-RMRG
WECC-CA/MX
WECC-SRSG
WECC-NWPP-US



Executive Summary

Over the past decade, variable energy resources are steadily replacing conventional forms of generation. To effectively assess industry plans with changing resource mixes, NERC has increasingly used probabilistic assessments as a tool to identify potential reliability risks. With various resource portfolios and distinct plans to meet electricity reliability requirements across the Bulk Electric System (BES) and Bulk Power System (BPS), the NERC Probabilistic Assessment Working Group (PAWG)) recognizes that each region may have unique risks to consider and assess. This report describes the assessments of Regional Risk Scenarios. This model allowed system planners to more closely study area-specific reliability risks and their uncertainties by using probabilistic methods. It is important to recognize that the BES (and by extension the BPS), across the six NERC Regions and Assessment Areas, is diverse in terms of planning and operations processes, as well as their associated risks. The assessment utilized a comprehensive and peer-review process for each Assessment Area's respective methods, assumptions, and results.

The Sensitivity Case scenarios include the following:

- MISO (MRO) – Increased demand response as a percentage of the overall resource mix
- Manitoba Hydro (MRO) – Variations in low water conditions with external assistance limitations
- SaskPower (MRO) – Impact of low hydro conditions on its system reliability
- SPP (MRO) – Low wind resource output with an increase in conventional generation forced outages
- NPCC – Planned/expected future capacity or resources may not materialize
- PJM (RF) – Planned/expected future capacity or resources may not materialize
- SERC – Impact of planned maintenance outage on system risk
- ERCOT (TRE) – Impacts of a difference in the realized frequency of high load and low wind output events
- WECC - Impacts to resource adequacy associated with potential coal-fired generation retirements.

Regions were requested to compare the purported risk factor results in the Probabilistic Assessment (ProbA) Sensitivity Case to the ProbA Base Case results from the 2020 NERC LTRA. These comparisons between the Base and Sensitivity Cases, combined with the trending results compared from the 2018 ProbA (found in the 2018 LTRA), provide a complete analysis to better understand underlying uncertainties and benchmark system risks. At regional discretion, the scenarios intentionally stressed the assumptions to study their associated impacts on the probabilistic indices. Although mitigation efforts were not the intended focus of the study, some regions provided rationale on expected methods to mitigate against that chosen risk.

Key Findings

Sensitivity results were varied across the study and dependent on their underlying assumptions. In some Assessment Areas such as Manitoba Hydro, SaskPower, PJM, and all Assessment Areas of NPCC, the study demonstrated that the risks were not significant, did not impact the probabilistic indices, or could be mitigated using preventive planning and operating measures. Other Assessment Areas noted potential risks if the chosen scenario were to materialize under the sensitivity assumptions. SPP determined Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE)[1] increases in their scenario, mostly occurring on or around the peak hour. SERC also noted low to moderate increases in their Loss of Load (LOL) indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that in many regions across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the amount of available external assistance between Assessment Areas and the penetration of coal resources in their respective portfolios. High level results of the Regional Risk Scenarios performed by Assessment Area can be found in Table ES.1. To understand the results in Table ES.1, see each Assessment Area's section of the report for the comparison of these values to the base case Probabilistic Assessment results as well as any additional references provided in Appendix E.

[1] For information on interpreting the values of EUE and LOLH used to evaluate the scenarios, see NERC PAWG Probabilistic Adequacy and Measures Report

Table ES.1: Summary of Regional Risk Scenario for Each Assessment Area[2]				
Assessment Area	2022		2024	
	Expected Unserved Energy [MWh/yr]	Loss of Load Hours [hrs/yr]	Expected Unserved Energy [MWh/yr]	Loss of Load Hours [hrs/yr]
MRO				
MISO[3]	N/A	N/A	27.69	0.24
Manitoba Hydro	45.13	1.79	0.05	0.06
SaskPower	319.20	3.50	59.70	0.60
SPP	N/A	N/A	72.60	0.11
NPCC				
New England	5.30	0.01	88.10	0.14
Maritimes	4.16	0.08	6.72	0.13
New York	0.68	0.00	13.90	0.05
Ontario	0.09	0.00	79.96	0.14
Québec	0.00	0.00	0.00	0.00
RF				
PJM	0.00	0.00	0.33	0.00
SERC[4]				
Central	N/A	N/A	12.20	0.02
East	N/A	N/A	517.40	0.57
Southeast	N/A	N/A	7.50	0.01
Florida Peninsula	N/A	N/A	513.30	0.52
Texas RE				
ERCOT[5]	N/A	N/A	64.72	0.05
WECC				
BC	0.00	0.00	0.00	0.00
AB	0.00	0.00	0.00	0.00
CA/MX[6]	1,005,716	32.00	2,402,976	71.00
SRSG	212	14.00	437	22.00
NWPP-US	14,681	Less than 1	274,091	6.00

Recommendations

With an increasing amount of uncertainty expected on the BPS with regional resource transitions, the PAWG recommends further increasing the use of probabilistic methods and scenarios to adequately study the reliability risks and to determine the sensitivity of those risks for various scenarios. The PAWG also recommends increasing the coordination between industry operations and planning personnel to further develop assumptions for probabilistic reliability assessments. These collaborations and studies could better inform, strengthen, and reinforce the fundamental BPS planning and operations processes to meet future reliability needs.

[2] An "N/A" is denoted where the Assessment Area chose not to perform the Risk Scenario for the optional study year.
[3] MISO's scenario has many different amounts of Demand Response entered in 2024. This table uses the maximum Demand Response added in their scenario.
[4] SERC performed an extensive stressing of their system to start at a higher LOLE than from the Base Case and performed many different multiplications of their capacity on maintenance. This table uses the maximum reported EUE and LOLH at the extreme scenario.
[5] ERCOT's scenario contained many different load draws. The one that produced the highest EUE and LOLH are presented in this table.
[6] See the Western Assessment in Appendix E for detailed assumptions, findings, and recommendations over what is reported in this document.

Introduction

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and support probabilistic resource adequacy efforts of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force (PAITF)[7] with the Probabilistic Assessment Improvement Plan.[8] Specifically, the group researches, identifies and details probabilistic enhancements applied to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[9] and the Reliability Issues Steering Committee (RISC) report[10] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

NERC regularly utilizes reliability assessments to objectively evaluate the reliability of the North American Bulk Power System (BPS). On a biennial basis, the NERC PAWG performs a Probabilistic Assessment (ProbA) to supplement the annual deterministic NERC Long Term Reliability Assessment (LTRA) analysis. The ProbA calculates monthly Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH)[11] indices for years 2 (Y2) and 4 (Y4) of the 10-year LTRA outlook (2022 and 2024 for the 2020 LTRA[12], respectively) and contains two studies: a Base Case and a Sensitivity Case. The two differ in that the Base Case contains assumptions under normal, anticipated operating conditions, and study results were each peer-reviewed by the NERC PAWG, NERC RAS and NERC Reliability and Security Technical Committee (RSTC) to ensure comparisons made in the LTRA can be applied across entities. Complete details and underlying assumptions of the 2020 ProbA Base Case analysis were included in the published 2020 LTRA in December 2020. The Sensitivity Case provides NERC a way to characterize more "what-ifs" in terms of the probabilistic methods used in each region. For the 2020 ProbA Sensitivity Case, the PAWG developed a Regional Risk Scenarios approach specific to each assessment area. Each region and assessment area has varied resource mixes, leading to different study focuses between assessment areas. The assessment areas identified and studied respective risk factors to better understand the reliability implications across all hours (instead of just the peak hour) using probabilistic methods. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across the BPS. Y2 and Y4 indices were reported for the Base Case study. For the Sensitivity Case, assessment areas were required to perform the analysis on Y4 and Y2 was optional.

Chapters in this assessment are primarily divided by the Regional Risk Scenario chosen for the 2020 ProbA. While Regional Risk Scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences. These results are used to inform system planners and operators about potential emerging reliability risk. The PAWG intends to utilize these study results in future probabilistic resource adequacy studies (such as trending applications) to develop further guidance for future work activities, where prominent, key points and takeaways are called out.

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[7] Probabilistic Assessment Improvement Task Force (PAITF)
[8] Probabilistic Assessment Improvement Plan
[9] See Focus Areas 1 and 4: ERO Enterprise Long-Term Strategy
[10] See Risk 1: Reliability Issues Steering Committee (RISC)
[11] NERC PAWG Probabilistic Adequacy and Measures Report
[12] NERC_LTRA_2020.pdf

Chapter 1: MRO - MISO

MISO is a summer peaking system that spans 15 states and consists of 36 Local Balancing Areas which are grouped into 10 Local Resource Zones (LRZs). For the 2020 NERC Probabilistic Assessment, MISO utilized a multi-area modeling technique for the 10 LRZs internal to the MISO footprint. Firm external imports as well as non-firm imports were also modeled within the cases.

Key Assessment Takeaway

MISO found that as the percent of Demand Response resources increased in their system, their Reliability Indices could double or triple. This is due to the need to call on Demand Response more and earlier in the year, leaving them unavailable for future calls in the year.

Risk Scenario Description

For the 2020 Probabilistic Assessment Risk Scenario, MISO performed a sensitivity analysis that examined the effects of increasing Demand Response (DR) resources as a percentage of the overall resource mix. Over the past several years the amount of DR in MISO has been steadily increasing. For DR to qualify as a capacity resource in MISO, it must be available for a minimum of 5 calls per year and 4 hours per day. These minimum dispatch requirements make up much of the DR that currently participates in MISO's capacity market.

MISO conducts a Loss of Load Expectation (LOLE) study annually to determine the amount of reserves required to meet the 1-day-in-10-years LOLE standard. In this study, each individual DR resource in MISO is modeled with their registered dispatch limits. There are cases in that analysis where all the available dispatches for DR would be used and load shed occurred as a result. This discovery prompted a desire to further investigate the effect that dispatch limited DR has on reliability. See Appendix E for details on where to find the report.

To perform this analysis, MISO began from the 2024 base case ProbA scenario. DR, totaling 5,000 MW, was then added to the resource mix in increments of 1,000 MW evenly distributed among the 10 LRZs while simultaneously removing 1,000 MW of generation. Doing this allowed MISO to examine how the risk changes from the base case as DR makes up an increasing amount of reserves.

Base Case Results

MISO's Base Case results, reproduced here, show a small amount of EUE and LOLH which is consistent with past ProbA results. Since MISO is a summer peaking system, most of the risk occurs during the summer months (June – Sept) as expected. However, there are cases where off-peak risk occurs due to certain zones being import limited[13] during periods of high planned outages.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**21.6%**	**17.6%**
Reference	**18.0%**	**18.0%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**27.3**	**14.3**
EUE (ppm)	**0.038**	**0.020**
LOLH (hours/year)	**0.196**	**0.085**

Risk Scenario Results

Currently, DR makes up roughly 4.9% of the total resource mix in MISO. This percentage is reflected in the Base Case results and served as a starting point for the Risk Scenario study. From that starting point, an additional 5,000 MW of DR was added to the system in increments of 1,000 MW. The percentage of DR to the overall resource mix can be found in Table 1.1.

[13] Detailed studies on these hours are found in the report linked in Appendix E

Table 1.1: Demand Response Percentage of Overall Resource Mix	
Demand Response Added [MW]	**Percent of Overall Resource Mix [%]**
Base Case	4.9
1,000	5.5
2,000	6.1
3,000	6.8
4,000	7.4
5,000	8.1

EUE and LOLH values were recorded for each iteration of increasing DR. As shown in the chart below, when DR increases as a percentage of total resources, EUE and LOLH also increase. By the time an additional 5,000 MW of DR was added, the EUE had nearly doubled and LOLH nearly tripled when compared to the Base Case. The increased risk is driven by the dispatch limits of DR. As previously mentioned, most DR in MISO is only available for 5 calls per year and 4 hours per day. As DR begins to make up more of the resources on the system, these resources most likely will exhaust their dispatch limits sooner and become unavailable for the remainder of the year. Historically, DR in MISO was credited in the capacity market solely based on its registered MW. Recently, MISO implemented enhanced accreditation rules for DR that considers dispatch limits and lead times, which will allow MISO to more effectively access the capabilities of DRs to maintain system reliability. As the region's risk profiles continue to evolve with the changing resource mix, MISO is continuously enhancing its resource adequacy planning process and is looking into sub-annual planning approach to sufficiently capture and mitigate risks across the year.

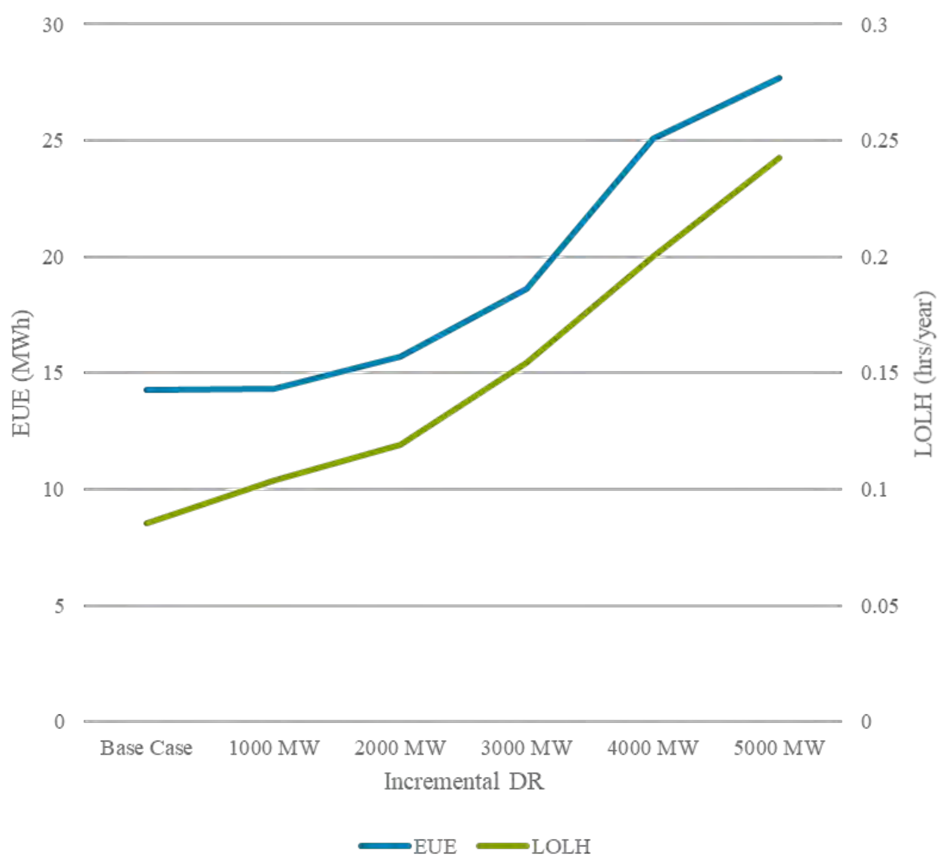

Figure 1.1 MISO Regional Risk Scenario EUE and LOLH[14]

[14] Note that the EUE and LOLH shown here increase as DR replaces traditional generation in increments of 1,000 MW

Chapter 2: MRO – Manitoba Hydro

Key Assessment Takeaway

Manitoba Hydro's reliance on hydro facilities can be susceptible to low water conditions for a given year. This is mitigated by proper management of reservoirs.

Manitoba Hydro (MH) system has approximately 6,900 MW (nameplate) of total generation. The system is characterized by around 4,350 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via the Nelson River HVdc transmission system. MH also has about 1,858.4 MW of hydraulic generation distributed throughout the province. In addition, 258.5 MW of wind generation and 412 MW thermal generation are distributed in the southern part of the province. The MH system is interconnected to the transmission systems in the Canadian provinces of Saskatchewan and Ontario and the US states of North Dakota and Minnesota.

The 2020 NERC Probabilistic Assessment for the MH system was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company (GE). The reliability indices of the annual Loss of Load Hours (LOLH) and the Expected Unserved Energy (EUE) for 2022 and 2024 were calculated by considering different types of generating units (thermal, hydro and wind), firm capacity contractual sales and purchases, non-firm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty and demand side management programs. The data used in the MARS simulation model are consistent with the information reported in the 2020 LTRA submittals from MH to NERC. On a winter accredited capacity basis, the resources within Manitoba are 92.76% hydro, 0.84% wind, and 6.41% thermal.

Risk Scenario Description

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance such as the water resource conditions, energy exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast, demand responses, energy efficiency and conservation programs, wind penetration and generation fleet availability.

The vast majority of MH's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2020 Assessment, MH has examined the impact of the most significant factor over the long run - variations in water conditions as detailed in the following:

1. Analyze the system as is to establish base reliability indices (Base case)
2. Variations in water conditions: model a 10-percentile low water condition and report the indices

All hydro units are modeled as Type 2 energy limited units in MARS[15]. The MARS input parameters for each hydro power plant are installed/in-service and retirement dates, monthly maximum and minimum output of each plant and monthly available energy from each plant. Each energy limited hydro unit is scheduled on a monthly basis. The first step is to dispatch the unit's minimum rating for all of the hours in the month. The remaining capacity and energy are then scheduled as needed as a load modifier during the Monte Carlo simulation.

Base Case Results

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	2024

[15] Type 2 units in the MARS program are "energy-limited units are described by specifying a maximum rating, a minimum rating and a monthly available energy" as stated in their program manual

Anticipated	**16.6%**	**16.0%**
Reference	**12%**	**12%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**2.7077**	**3.3831**
EUE (ppm)	**0.1072**	**0.1329**
LOLH (hours/year)	**0.0033**	**0.0039**

The base case LOLH values calculated for the reporting year of 2022 and 2024 are virtually zero. Non-zero EUE are obtained but these values are small. These results are mainly due to the larger forecast reserve margin and the increase in the transfer capability between Manitoba and US due to the addition of the new 500 kV tie line between Manitoba and Minnesota. The base case LOLH and EUE values calculated in this assessment for the reporting year of 2022 increase a bit from those zero values obtained in 2018 assessment for the reporting year of 2022. This is expected as result of modeling improvement and changes in assumptions. The most significant model improvement for 2020 Probabilistic Assessment is that Manitoba Hydro modeled seven (7) different load shapes using actual historical data to capture the uncertainties associated with load profiles and peak load forecast. In 2018 assessment, only a typical year load profile was used to model the annual load curve shape.

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**45.13**	**56.38**
EUE (ppm)	**1.7870**	**2.2150**
LOLH (hours/year)	**0.0544**	**0.0643**

Hydro flow condition is the most significant parameter that characterizes Manitoba Hydro's system resource adequacy. In the 2020 assessment Manitoba Hydro has examined variations in water conditions in the scenario analysis. Scenario analysis results show that LOLH and EUE values increase for both 2022 and 2024 when an extreme drought scenario is modeled. Water flow conditions of 10 percentile or lower tend to increase the loss of load hours and expected unserved energy. As a small winter peaking system on the northern edge of a large summer peaking system (MISO), there generally assistance available, particularly in off peak hours, to provide energy to supplement hydro generation in low flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Chapter 3: MRO – SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of approximately 652,000 square kilometers (251,739 square miles) with approximately 1.2 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan. SaskPower is the principal supplier of electricity in the province and responsible for serving over 540,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections

Key Assessment Takeaway

SaskPower's lower quartile hydro scenario increases the risk due to higher Reliability Indices, as expected, but did not rise significantly. Such increases can be mitigated by reliance on emergency procedures, if required.

Risk Scenario Description

SaskPower analyzed the impact of low hydro conditions on its system reliability. The low hydro forecast is based on 25 percentile hydro flow conditions. Hydro units constitute approximately 20 percent of Saskatchewan's net installed generation capacity and it hasn't experienced significantly low hydro conditions since 2001. The region consists of three main river systems and one river system experiencing low flow conditions doesn't necessarily indicate that the other systems would experience the same conditions. Although, there is low probability of low flow conditions experienced by all the river systems in the same year, the sensitivity scenario tests the system's resiliency when the hydro units have less energy for dispatch, and subsequently limited peak load shaving capability. Furthermore, this risk scenario has become more relevant since the Saskatchewan government announced in July 2020 that it intends to pursue a $4 billion irrigation project at Lake Diefenbaker which could impact the future water flows available for hydro generation by SaskPower by limiting the water flow, and thus energy available, for such generation.

The methodology used to derive the various hydro conditions is based on the historical hydrological records in the basin. Before using these historical hydrological records to model any flow scenarios, adjustments were applied to these records, which includes historical and present upstream water uses, changes in water management, and naturalized flow records if necessary. The long-term forecasts typically use low (lower quartile), best (median) and high estimate (upper quartile) flows based on the current level of development adjusted historical records. Hydro units are modelled as Type 2 energy limited units in MARS. The median quartile hydro conditions in the base case were replaced with lower quartile hydro conditions for the sensitivity scenario.

Base Case Results

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period. The major contribution to the Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) is in the off-peak periods due to maintenances scheduled for some of the largest units.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**34.2%**	**30.0%**
Reference	**11%**	**11%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**80.4**	**26.4**
EUE (ppm)	**3.34**	**1.07**
LOLH (hours/year)	**0.96**	**0.28**

SaskPower did further analysis changing some of the fixed unit maintenances in year 2022 and let the model schedule it automatically to lower system risk of loss of load. With changing the unit maintenances, EUE reduced by more than 50 percent. Most of the maintenances are scheduled during off-peak periods and can be rescheduled to mitigate short–term reliability issues when identified.

Since the 2018 Probabilistic Assessment, the reported forecast reserve margin for 2022 has increased, mainly due to reductions in the load forecast.

Risk Scenario Results

Modelling Hydro units using Lower Quartile Hydro Conditions result in higher loss of load values as compared to the base case. It is to be expected but this increase in the LOLH and EUE is not anticipated to cause any reliability issues. Since the difference in LOLH and EUE values between the Base Case and Sensitivity Case is quite low, its affects can be mitigated using emergency assistance if needed.

Sensitivity Case summary of Results

	2022	2024
EUE (MWh)	**319.2**	**59.7**
EUE (ppm)	**13.2**	**2.4**
LOLH (hours/year)	**3.5**	**0.6**

Chapter 4: MRO - SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP Assessment Area is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Key Assessment Takeaway

Southwest Power Pool demonstrated that many low probability events overlaid can impact their Reliability Indices. A significant increase in forced outage rates, coupled with a low wind output, on a hot summer day can create the conditions for increased risk to EUE and LOLH. This scenario resulted with over 99% of the potential risk identified occurring during summer peak load hours and demonstrated a higher loss of load risk between the scenario studied and the Base Case.

Risk Scenario Description

SPP has seen an increase in installed wind and a slight increase in forced outage rates over the past few years. Therefore, SPP chose a low wind output scenario paired with an increase in conventional forced generation outages as the 2020 ProbA Regional Risk Scenario. The historical weather year chosen was the lowest capacity factor output on summer peak hours between years 2012 to 2019 was used to model a low wind scenario. When determining the lowest performing wind year, only peak hours (Hour Ending 1 PM to 8 PM) during months June, July, and August were analyzed to derive the average capacity factor by year. Through this analysis, 2012 wind year was modeled with each historical load year (2012 to 2019) in the risk scenario. The weighted forced outage rate of the Base Case study was approximately 12.5%. The weighted forced outage rate for all conventional resources were increased proportionally and applied to each resource to achieve an SPP weighted forced outage rate of 15%. The regional risk scenario was performed on year 2024 to reflect additional generation retirements and projected installed wind capacity.

Base Case Results

No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP Assessment Area. Reserve margins are well above 20% in both study years and no major impacts were observed related to resource retirements. In addition, the 2018 Probabilistic Assessment Base Case results for 2022 were the same for the 2020 Base Case results, i.e., zero loss of load.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	27.6%	26.8%
Reference	15.8%	15.8%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.00**
EUE (ppm)	**0.00**	**0.00**
LOLH (hours/year)	**0.00**	**0.00**

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**--**	**72.6**
EUE (ppm)	**--**	**2.44**

LOLH (hours/year)	--	**0.113**

The results of the risk scenario showed an increase of potential loss of load, which reflects a slight increase in summer forced outages paired with a low output wind year across the summer peak periods. Scenario analysis results show that LOLH and EUE values increase for 2024 when compared to the base case results. The modeling of the lowest wind output year paired with all load years showed the most impact in contributing approximately 80% to the increase of EUE and LOLH. Over 99% of the EUE and LOLH events occurred during the summer season. All risk was identified on peak load hours.

Chapter 5: NPCC

The Northeast Power Coordinating Council (NPCC) region has five Assessment Areas. The following pages contain the results for each Assessment Area. For each of the Risk Scenario results sections, a link to a more detailed report covering the modeling assumptions and results can be found in Appendix E. Note that the metrics estimated are consistent with NPCC's Resource Adequacy – Design Criteria[16].

Key Assessment Takeaway

NPCC's Assessment Areas generally pursued removing Tier 1 resources as their risk scenario, with the exception of Ontario's choice to study nuclear refurbishment project delays. The assessment demonstrated that with the removal of Tier 1 resources and transmission projects, the NPCC Area Reliability Indices did not notably increase from the Base Case for all Assessment Areas, including Ontario. In general, the scenario results also emphasized the risks shown in the Base Case analysis and are consistent with other resource adequacy analysis.

NPCC - Maritimes

The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas. It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a population of 1.9 million. There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. Demand for the Maritimes Area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas.

Risk Scenario Description

Tier 1 resources[17] were removed in other NPCC areas. The low levels of Tier 1 resources in the Maritimes Area would not be an adequate test for severe conditions. For this reason, the Area assumed the winter wind capacity is de-rated by half (1224 MW to 612 MW) for every hour in December, January, and February to simulate widespread icing conditions and that only 50% (from 532 MW to 266 MW) of natural gas capacity is available due to winter curtailments of natural gas supplies. Dual fuel units are assumed to revert to oil.

The Area has a diverse resource mix, and this scenario tests the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios did not meet the degree of severity and likelihood. This scenario was chosen to allow a direct comparison between the NERC and NPCC probabilistic analyses as the same severe scenario was used for both.

The results of this risk scenario are valuable to resource planners since they demonstrate a high level of reliability by meeting the NPCC loss of load expectancy (LOLE) target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. Hence, since the LOLH value for both the base case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The base case reserve margin for 2022 was 21%, slightly higher than the Area's target of 20%. In the short term, unexpected delays in the development of Advanced Metering Infrastructure in New Brunswick which led to conservative short term increases in load forecasts, on peak sales of firm capacity to neighboring jurisdictions, and

[16] i.e., they are calculated following all possible allowable "load relief from available operating procedures". For more information see Directory #1 (npcc.org)

[17] The term "Tier"" is used to describe categories of resources. This document is to be read alongside the NERC Long-Term Reliability Assessment that defines these categories.

retirement of small thermal generators in PEI and NM has reduced the base case planning reserve margins to levels slightly below the target levels of 20% in 2024, respectively.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.3%	20.9%
Reference	20.0%	20.0%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.575**	**1.125**
EUE (ppm)	**0.021**	**0.039**
LOLH (hours/year)	**0.010**	**0.023**

For the two studied years, this gave rise to non-zero values of EUE and LOLH with pronounced weighting during the months of December, January, and February, however the values are low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 0.575 MWh and 0.010 hours, respectively. The results are slightly worse for 2024 at 1.125 MWh and 0.023 hours, respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.021 and 0.039 for the years 2022 and 2024, respectively.

Risk Scenario Results

As expected, with the additional loss of half of the Area's wind and natural gas resources over and above the normal probability for loss of system resources, the risk scenarios reduce both the planning reserve margins to levels below the Area's target of 20%. Forecast ranges for planning reserves are 17% and 15% for the two study years of 2022 and 2024, respectively.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**4.161**	**6.718**
EUE (ppm)	**0.149**	**0.236**
LOLH (hours/year)	**0.077**	**0.113**

For the two studied years, this gave rise to non-zero values of EUE and LOLH again with pronounced weighting during the months of December, January, and February and again the values are still low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 4.161 MWh and 0.077 hours respectively. The results are slightly worse for 2024 at 6.718 MWh and 0.128 hours respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.149 and 0.236 for the years 2022 and 2024.

NPCC - New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional bulk power system (BPS). The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Risk Scenario Description

Currently, in the probabilistic reliability analysis, the seasonal capacity ratings of the wind and solar resources are represented by a single value applicable to every hour of the day. The single value of the seasonal rating is based on the resource's seasonal claimed capability that are established using its historical median net real power output during the reliability hours (hours ending 14:00 through 18:00 for the summer period, and 18:00 through 19:00 for the winter period). As the system evolves with higher Behind-the-Meter solar penetration, the daily peaks may occur in the hours outside of the established reliability-hours window. The reduction in the wind and solar resources' rating is meant to identify the impact on system reliability if the current rating methodology overstates the capacity value of these resources in the future with the peaks occurring in different hours. The removal of the Tie 1 future resources is to take a conservative approach and identify the reliability consequences to the New England system if the in-service of these future resources is delayed.

Base Case Results

For year 2022, the 2018 study estimated an annual LOLH of 0.007 hours/year and a corresponding EUE of 2.713 MWh. In this year's study, the LOLH and the EUE slightly increased to 0.008 hours/year, and 3.292 MWh, respectively.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**29.4**	**18.95**
Reference	**13.9**	**12.7**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**3.292**	**58.62**
EUE (ppm)	**0.027**	**0.471**
LOLH (hours/year)	**0.007**	**0.095**

For year 2024, results show that the LOLH and the EUE values will increase to 0.095 hours/year, and a corresponding EUE of 58.618 MWh. The increase in LOLH and EUE is mainly attributed to the expected retirement of Mystic Units 8 and 9 (~1,400 MW) in the Boston area.

Risk Scenario Results

As expected, assuming less capacity contribution from the wind and solar resources and the delay of Tier 1 new resources will increase the LOLH and the EUE of the system. The LOLH and the EUE values are estimated to increase to 0.011 hours/year, and 5.3 MWh for 2022, respectively and to 0.135 hours/year, and 88.1 MWh for 2024, respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.038 and 0.625 for the years 2022 and 2024.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**5.3**	**88.1**
EUE (ppm)	**0.038**	**0.625**
LOLH (hours/year)	**0.011**	**0.135**

NPCC - New York

The New York ISO (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. This represents approximately 37,317 MW[18] of Existing-Certain resources and Net Firm transfers anticipated for 2021. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Risk Scenario Description

This scenario evaluates the reliability of the system under the assumption that no major Tier 1 generation (see Table 5.1) or transmission (see Table 5.2) projects come to fruition within the ProbA study period. Below is a list of the major Tier 1 proposed transmission and generation projects that were removed from the Base Case.

Table 5.1: Tier 1 Generation Projects for NPCC – New York

Unit Name	Name Plate [MW]	Zone	2020 RNA COD
Ball Hill Wind	100	A	12/2022
Baron Winds	238.4	C	12/2021
Cassadaga Wind	126.5	A	12/2021
Eight Point Wind Energy Center	101.8	B	12/2021

[18] NERC_LTRA_2020.pdf

Calverton Solar Energy Center	22.9	K	12/2021
Roaring Brook Wind	79.7	E	12/2021

Table 5.2: Tier 1 Transmission Projects for NPCC – New York						
Queue #	**Project Name**	**Zone**	**CRIS Request**	**SP MW**	**Interconnection Status**	**2020 RNA COD (In-Service Date)**
Proposed Transmission Additions, other than Local Transmission Owner Plans (LTPs)						
Q545A	Empire State Line	Regulated Transmission Solutions	N/A	N/A	Completed TIP Facility Study (Western NY PPTPP)	5/2022
556	Segment A Double Circuit				TIP Facility Study in progress (AC PPTPP)	12/2023
543	Segment B Knickerbocker-Pleasant Valley 345 kV				TIP Facility Study in progress (AC PPTPP)	12/2023
SDU	Leeds-Hurley SDU	System Deliverability Upgrades (SDU)	n/a	n/a	SDU triggered for construction in CY11	Summer 2021
CRIS Request						
430	Cedar Rapids Transmission Upgrade	D	80	80	CY17	10/2021

This scenario provides an indication of the potential reliability risks related to projects relied upon in the NYISO's 2020–2021 Reliability Planning Process not materializing.

Base Case Results

The MARS planning model was developed by NPCC with input from each Area (Ontario, New York, New England, Quebec, and Maritimes). The New York Loss of Load Hours (LOLH) for 2022 and 2024 are 0.003 and 0.029 (hours/year), respectively, with corresponding Expect Unserved Energy (EUE) values of 0.594 and 6.837 (MWh), respectively. These values trend higher than the past ProbA results. The trend is mainly due to the decrease in the forecasted Prospective Reserve Margin and Operable Reserve Margins.[19] The New York area is summer-peaking and the LOLH and EUE risk occurs primarily during the summer months.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.8%	18.6%
Reference	15.0%	15.0%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.594**	**6.837**
EUE (ppm)	**0.004**	**0.046**
LOLH (hours/year)	**0.003**	**0.029**

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**

[19] As defined by NERC for the Long-Term Reliability Assessments (LTRA) and Probabilistic Assessment (Prob A) application.

EUE (MWh)	**0.681**	**13.904**
EUE (ppm)	**0.005**	**0.093**
LOLH (hours/year)	**0.003**	**0.045**

As expected, if no major Tier 1 transmission and generation projects are assumed to come in-service within ProbA Study Period, the LOLH and EUE results are observed to be higher than ProbA Base Case. The LOLH for 2022 and 2024 are 0.003 and 0.045 (hours/year), respectively, with corresponding EUE values of 0.681 and 13.904 (MWh). Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.005 and 0.093 for the years 2022 and 2024.

NPCC - Ontario

The Ontario Independent Electricity System Operator (IESO) is the Planning Coordinator, Resource Planner and Balancing Authority for Ontario, as defined by the North American Electric Reliability Corporation. As detailed in Section 8 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO follows the Northeast Power Coordinating Council resource adequacy criterion. ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighboring Planning Coordinator Areas as contributing to resource adequacy needs in the Annual Planning Outlook resource adequacy assessments.

Risk Scenario Description

Ontario currently has 18 nuclear units, six of which are expected to retire by 2024/2025. As of today, one unit has been refurbished with nine more units being refurbished over the next decade. Given the size of each nuclear unit, there is a significant risk to resource adequacy if the return of any unit is delayed due to unforeseen circumstances. For this reason, the IESO chose refurbishment project delays for their risk scenario. Additionally, the demand forecast was increased by 5% for Ontario risk scenario to reflect possible rapid economic recovery from COVID-19 impacts.

Removing Tier 1 resources would not have been an appropriate scenario to test the system because those resources amounted to only 360 MW.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	20.1%	11.3%
Reference	23.8%	16.8%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.049**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

Base Case Results

The previous ProbA estimated an annual LOLH of 0.0 hours/year and EUE of 0.0 MWh for the year 2022. The median peak demand forecast for 2022 has increased by 2.5% compared to the 2018 forecast. The current forecasts are LOLH of 0.0 hours/year and EUE of 0.049 MWh for the year 2022. No difference in the estimated LOLH and a marginal difference in EUE are observed between the two assessments.

Risk Scenario Results

The ProbA Risk Scenario estimated an annual LOLH of 0.0013 hours/year and EUE of 0.0925 MWh for the year 2022. For the year 2024, the estimated annual LOLH was 0.171 hours/year and EUE was 99.7 MWh, as expected. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.000 and 0.692 for the years 2022 and 2024.

The results emphasize the resource adequacy needs that Ontario faces in the mid to long-term. The IESO is transitioning to the use of competitive mechanisms with stakeholder inputs to meet Ontario's adequacy needs.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**0.0925**	**99.7**
EUE (ppm)	**0.000**	**0.692**
LOLH (hours/year)	**0.0013**	**0.171**

NPCC - Québec

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC Area that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Risk Scenario Description

In this scenario, it is assumed that Tier 1 resources be removed to test the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios are less likely compared to this scenario.

Base Case Results

The base case reserve margin for 2022 was 13.2%, which is higher than the Area's reference reserve margin of 10%.

In the short term, increase in load forecasts, on peak sales of firm capacity to neighboring jurisdictions reduced the base case planning reserve margins to levels slightly below the reference reserve margin of 10% in 2024.

For the two studied years, the results are zero for EUE and LOLH. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are zero for the years 2022 and 2024.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	13.5%	14.0%
Reference	10.1%	10.1%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.000**
EUE (ppm)	**0.00**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**

Risk Scenario Results

As expected, after removing all Tier-1 resources, the risk scenarios reduce both the planning reserve margins to levels

below the Area's target of 10%. Forecast ranges for planning reserves are 13.0% and 8.9% for the two study years of 2022 and 2024, respectively. For the two studied years, the EUE and LOLH remain close to zero.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**0.00**	**0.000**
EUE (ppm)	**0.00**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**

Chapter 6: RF - PJM

PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is part of the Eastern Interconnection and serves approximately 65 million people over 369,000 square miles.

Key Assessment Takeaway

PJM decided to remove all Tier 1 resources as part of their scenario. They demonstrate no significant rise in Reliability Indices based on these removals.

Risk Scenario Description

The risk scenario considers the removal of all Tier 1 units[20] from the simulation. This scenario serves as a proxy for potential withdrawals or delays of queue projects in the PJM Interconnection Queue. PJM chose this scenario due to the delay in the Reliability Pricing Model's (RPM) schedule (resulting from the Minimum Offer Price Rules proceedings at FERC); RPM provides entry price signals for planned resources such as those labeled as Tier 1 resources. Furthermore, the risk scenario provides resource adequacy planners with an opportunity to analyze the impact of a higher RTO-wide forced outage rate on reliability metrics due to the fact that, in general, Tier 1 units are expected to have lower forced outage rates than existing units. This is because most Tier 1 units are combined cycle units. This scenario provides value to resource adequacy planners due to the fact that it considers reserve margins that are much lower than current reserve margins at PJM.

Base Case Results

The Base Case results in LOLH and EUE equal to zero for both 2022 and 2024 due to large Forecast Planning Reserve Margins (36.6% and 40.1%, respectively). These reserve margins are significantly above the reference values of 14.5% and 14.4%, respectively. Note that these large Forecast Planning Reserve Margin values include Tier 1 resources (~15,000 MW in 2022 and ~23,000 MW in 2024). Historically, a significant share of Tier 1 resources, 20%-30%, drop out of the Interconnection Queue process.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**33.5%**	**36.6%**	**40.1%**
Reference	**15.8%**	**14.5%**	**14.4%**
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.000**	**0.000**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**
2022*: results from the 2018 ProbA			

The LOLH and EUE in the 2020 study are identical to the values reported in the 2018 study. There are no differences in the EUE and LOLH results because in both studies the Forecast Planning Reserve Margin values are well above the reference values. Furthermore, the Forecast Planning Reserve Margin for 2022 in the 2020 study has actually increased compared to the value in the 2018 study due to a slightly higher amount (~300 MW) of Forecast Capacity Resources and a lower (~3,000 MW) Net Internal Demand value.

Risk Scenario Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**25.9%**	**24.1%**
Reference	**14.5%**	**14.4%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.330**
EUE (ppm)	**0.000**	**0.000**

[20] "Tier 1" resources refers to planned resources in the PJM Interconnection Queue with an executed Interconnection Service Agreement (or its equivalent). See footnote 15 for more reference to the term "Tier"

LOLH (hours/year)	**0.000**	**0.000**

Risk Scenario Results

The regional risk scenario yields LOLH and EUE values that are practically zero for both 2022 and 2024 (the EUE value of 0.33 MWh in 2024 is, for all intents and purposes, a negligible value).

These results are also caused by Forecast Planning Reserve Margins, even after excluding Tier 1 resources, which are well above the reference values (i.e., 25.9% vs a reference value of 14.5% in 2022 and 24.1% vs a reference value of 14.4% in 2024).

Note that PJM's anticipated reserve margins in the Base Case and the Risk Scenario are largely driven by past and expected outcomes of PJM's capacity market, the Reliability Pricing Model, which by design allows for the possibility of procuring reserve margin levels above the reference levels[21].

[21] Sections 3.1 – 3.4 in PJM Manual 18 available at https://www.pjm.com/~/media/documents/manuals/m18.ashx

Chapter 7: SERC

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. The regional entity includes four NERC assessment areas: SERC-East, SERC-Central, SERC-Southeast, and SERC-Florida Peninsula.

In addition to seeing loss of load risk during peak load summer months, SERC is also experiencing tighter operating conditions during non-summer months. One factor that has contributed to this trend is the amount of thermal generation resources taking planned maintenance outages during the shoulder months. While the LTRA projects reserves for summer, winter, and annual assessments, it may not highlight risk, if any, during spring and fall.

Key Assessment Takeaway

SERC's increase of maintenance outages on their Base Case did not demonstrate a significant increase of Reliability Indices. In response, SERC then altered their cases to ensure each of the regions started at a LOLE of 0.1. This change allowed SERC to determine their Reliability Indices produce an exponential relationship to the increase of maximum capacity undergoing maintenance. This is able to be mitigated by proper coordination of planned outages.

SERC has not experienced any reliability events directly related to planned maintenance outages. However, reports on events in neighboring regions highlight the importance of evaluating this risk for SERC. A FERC and NERC staff report on the 2018 cold weather event[22] identified that planned outages contributed to system reliability risk in the South-Central United States. Additionally, MISO declared Maximum Generation Events in January and May of 2019 which supports MISO's finding that the combination of high planned outages, reduced capacity availability, and volatile load has increased the risk of capacity shortages during non-summer months.[23]

Risk Scenario Description

To investigate the impact of planned maintenance outages on system risk, SERC conducted a sensitivity study in the 2020 Probabilistic Assessment that increased the amount of planned maintenance outages on the SERC system for year 2024. This sensitivity study helps resource adequacy planners understand how planned maintenance outages can impact the distribution of loss of load risk across all times of the year and it improves the ability to plan maintenance outage schedules that minimize loss of load risk.

SERC incrementally increased the planned maintenance rates for thermal resources to test the reliability of the SERC system under a scenario with higher levels of planned maintenance outages. Given that the base case metrics are very small for many of SERC's sub-regional areas, known as metric reporting areas (MRAs), we performed a two-part sensitivity study. One, starting with the base report and the other starting at each MRA's PRM resource level, where the starting point reserves were adjusted for each MRA to reach the LOLE target of 0.1 days/year. In both instances, the base case planned outage rates were multiplied by factors of 1.5, 2 and 2.5.

Base Case Results

The 2020 Probabilistic Assessment Base Case results show that each of the MRAs are projected to have reserves and access to imports from neighboring areas that are well more than that needed to meet the 0.1 days/year LOLE target. In the 2020 study year, the planning reserve margins (PRM) results are 21.8% for 2022 and 18.9% for 2024. These projections are higher than the SERC 2018 Probabilistic Assessment study. The increase in PRM could be attributed to several modeling changes in the 2020 study, particularly the integration of Florida Peninsula, a rapidly changing capacity mix, and updates to transfer capacities. The snippets of the 2020 LTRA tables for the base case results for all SERC MRAs are found below.

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[22] FERC and NERC Release Report on January 2018 Extreme Cold Weather Event

[23] Resource Availability and Need, Evaluation Whitepaper September 2018 and MISO January 2019 Max Gen Event Overview and May 2019 Max Gen Event Overview

SERC-Central: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	24.9%	26.4%	27.0%
Reference	14.4%	15.0%	15.0%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.000	0.001	0.001
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

SERC-East: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	24.9%	22.8%	23.9%
Reference	14.4%	15.0%	15.0%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.000	0.717	5.262
EUE (ppm)	0.000	0.003	0.024
LOLH (hours/year)	0.000	0.001	0.009

SERC- Southeast: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	32.4%	35.8%	39.1%
Reference	14.4%	15.0%	15.0%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	0.00	0.009	0.028
EUE (ppm)	0.00	0.000	0.000
LOLH (hours/year)	0.00	0.000	0.000

SERC-Florida Peninsula: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	2022	2024
Anticipated	N/A	21.6%	22.8%
Reference	N/A	15.0%	15.0%
Annual Probabilistic Indices			
	2022*	2022	2024
EUE (MWh)	N/A	22.66	2.262
EUE (ppm)	N/A	0.096	0.009
LOLH (hours/year)	N/A	0.035	0.004

An asterisk (*) denotes results from the 2018 ProbA

Risk Scenario Results

When using the maintenance multiplier of 1x, maintenance outages are primarily scheduled in March-May and September-November for SERC-C, SERC-SE, and SERC-E. In SERC-FP, maintenance outages are scheduled throughout the year, except for summer. Increasing the multiplier beyond 1.5x causes maintenance outages to begin to be scheduled in the peak load summer months. Figure 7.1 shows how the multipliers impact the maximum capacity undergoing maintenance during the simulation.

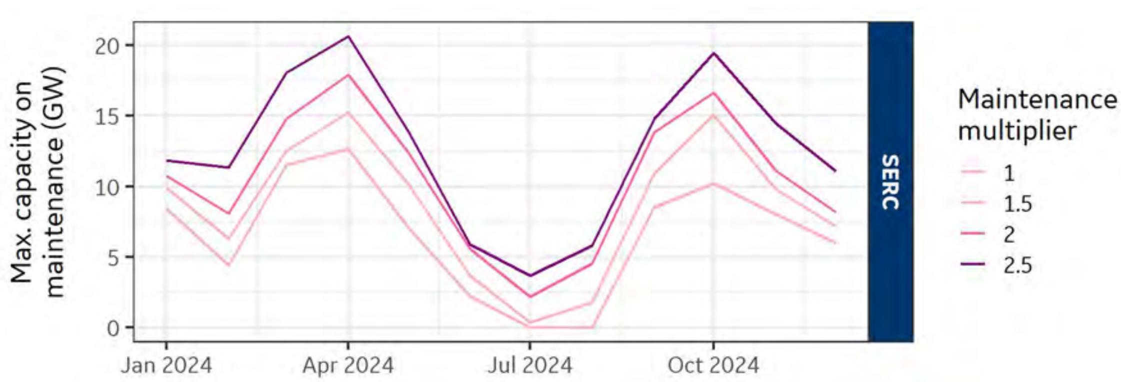

Figure 7.1 Maximum simultaneous capacity on maintenance outage for all of SERC

The reliability metrics for the base case are summarized in Table 7.1. The MRAs that had a measurable amount of LOLE in the base case (SERC-E and SERC-FP) see an increase in their observed metrics as the maintenance multiplier is increased. However, this increase in LOLE is somewhat moderate. For instance, in the case with double the maintenance rates, both SERC-E and SERC-FP have a LOLE below 0.1 days/year.

Table 7.1: Reliability Indices for Increased Maintenance for Base Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
SERC-C	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.002	1.1	0.005
	2.5	0.008	0.017	12.2	0.055
SERC-SE	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.001	0.4	0.002
	2.5	0.008	0.013	7.5	0.030
SERC-E	1	0.004	0.009	5.3	0.024
	1.5	0.012	0.019	12.3	0.056
	2	0.085	0.136	107.8	0.490
	2.5	0.277	0.574	517.4	2.349
SERC-FP	1	0.003	0.004	2.3	0.009
	1.5	0.018	0.024	19.1	0.079
	2	0.099	0.147	141.4	0.583
	2.5	0.320	0.518	513.3	2.114
SERC	1	0.006	0.013	7.6	0.006
	1.5	0.029	0.043	31.5	0.023
	2	0.183	0.284	250.8	0.186
	2.5	0.588	1.087	1,050.4	0.778

Given that the base case metrics are very small for many of the MRAs, SERC performed a second set of simulations to better understand the impact of higher maintenance outages in all MRAs. Instead of starting with the base case scenario, the starting point was the final step in the Probabilistic Assessment's interconnected PRM simulation, where every MRA in the model experiences a LOLE of 0.1 days/year. This provides a starting point with observable loss of load statistics for all the areas. Table 7.2 show that as the maintenance multiplier increases in the PRM case, all the MRAs experience an exponential increase of LOLE and other metrics. The increase is similar across all MRAs with the exception that SERC-FP experiences a larger-than-average increase in LOLE. Figure 7.2 also highlights this same exponential increases under this second simulation.

Table 7.2: Reliability Indices for Increased Maintenance for Planning Reserve Margin Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
SERC-C	1	0.100	0.263	255.8	1.166
	1.5	0.156	0.379	402.4	1.835
	2	0.594	1.517	2,139.7	9.757
	2.5	1.772	4.863	6,560.1	29.916
SERC-SE	1	0.099	0.233	280.9	1.113
	1.5	0.136	0.296	349.6	1.386

	2	0.521	1.131	1,418.4	5.623
	2.5	1.800	4.442	6,079.4	24,098
SERC-E	1	0.100	0.256	275.5	1.251
	1.5	0.142	0.331	343.8	1.561
	2	0.554	1.204	1,208.4	5.486
	2.5	1.799	4.634	5,218.9	23.691
SERC-FP	1	0.100	0.203	160.0	0.659
	1.5	0.261	0.440	394.7	1.626
	2	0.805	1.474	1,573.9	6.482
	2.5	2.321	4.810	5,484.6	22.588
SERC	1	0.307	0.767	1,527.0	1.131
	1.5	0.561	1.197	2,177.4	1.613
	2	1.908	4.485	8,815.7	6.532
	2.5	6.523	18.373	35,211.9	26.091

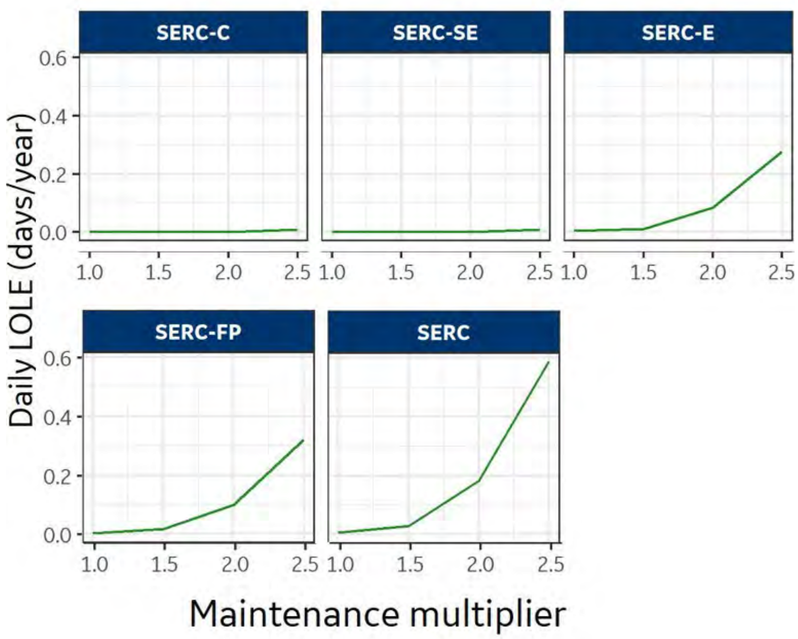

Figure 7.2 Loss of Load Statistics by Maintenance Multiplier per MRA

Figure 7.3 shows that under the 1x multiplier case, the majority of MRAs have the largest accumulation of LOLE in the summer. SERC-FP is the exception, with nearly 20% of the LOLE occurring during the winter. As the maintenance multiplier increases, most MRAs experience less LOLE in the summer and more LOLE in the spring and fall. SERC-FP is again the exception, with the majority of the LOLE moving to the winter and a smaller portion of LOLE moving to the fall.

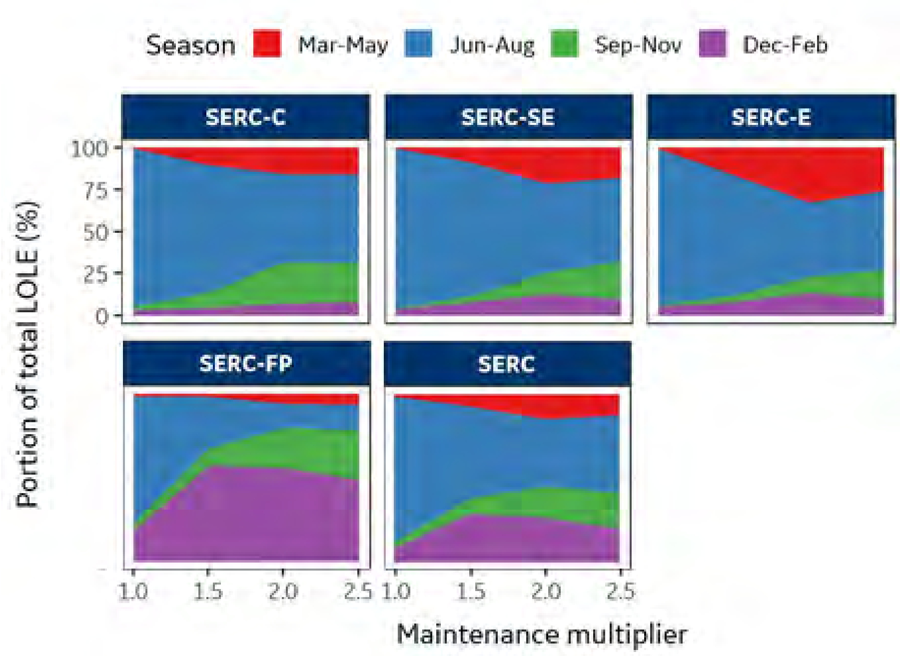

Figure 7.3 Seasonal LOLE Distribution for PRM Cases with Increased Maintenance

Risk and Recommendations

The sensitivity scenarios indicate that the risk in year 2024 associated with increased planned maintenance outages is low to moderate. For instance, the MRAs with the highest increase in LOLE, SERC-E and SERC-FP were still below 0.1 LOLE with double the maintenance rates. The small increase in LOLE for the SERC MRAs resulting from increased planned maintenance outages can be partially attributable to the fact that the SERC MRAs in 2024 are projected to have reserves and access to imports from neighboring areas that is well in excess of that needed to meet the 0.1 days/year LOLE target.

The results of this sensitivity study highlight the need for planned outage coordinators to develop unique maintenance schedules that align with expected local weather and system conditions. For this reason, the optimal time periods for scheduling maintenance outages vary across the SERC MRAs.

It is worth noting that the model assumes an optimized outage schedule based on foresight of average weather conditions. The GE MARS software schedules planned outages with a “packing” algorithm that schedules maintenance in the weeks with highest margins. A further comparison between the maintenance schedule developed by GE MARS and historical maintenance schedules could be insightful in understanding the findings of this sensitivity study. A redacted copy of the SERC 2020 Probabilistic Assessment report can be found in the SERC website by using the link in Appendix E.

Chapter 8: Texas RE – ERCOT

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas.

Key Assessment Takeaway

ERCOT demonstrates that by resampling their wind profiles with their load profile to emphasize low to moderate amounts of wind has a significant effect on their net load peaks, and as a result increase their Reliability Indices. This increase is similar to those that alter their system such that a LOLE of 1 day in 10 years is expected. This indicates that the ERCOT system increases in Reliability Indices for their scenario, while significant in comparisons to the Base Case, are not significant in comparison to industry accepted standards.

Risk Scenario Description

The total installed wind capacity in ERCOT is around 25 GW, and additional 13 GW of new wind is expected to come online in the next three to four years. Furthermore, the two Energy Emergency Alert (EEA) events in 2019 summer were primarily due to low output from wind resources. In addition, simulated loss of load events in ERCOT are largely driven by high load, low wind output conditions. These conditions occur with relative rarity such that a relatively small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the base case simulations. Other aspects of the study can be found in Appendix B.

To construct the alternate wind profiles which reflect a higher likelihood of low wind output, a filter was performed for days in the simulated base case which had any firm loss of load. An alternate wind profile for each day was randomly selected from the wind profiles from this set of days. This re-shuffling of load and wind profiles was performed 100 times. The sampled sets of profiles which represent the most extreme and 10th most extreme sets of net load profiles were selected to be simulated for 2024. The criteria for most extreme was based on the set with the highest average net loads in the top 40 net load days.

Base Case Results

The Base Case study results in minimal reliability events. As compared to the 2018 ProbA Study, the reserve margin has increased substantially primarily due to increase in solar resources. More than 12GW of additional solar installed capacity is expected in 2022 now than was forecast when the 2018 ProbA Study was published. Compared to the results from the 2018 ProbA Study, LOLH decreased from 0.87 to 0.00 for the first study year. The results are driven by an increase in the Anticipated Reserve Margin, resulting from growth in planned solar and wind capacity.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**19.1%**	**15.5%**
Reference	**13.8%**	**13.8%**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**.05**	**12.86**
EUE (ppm)	**0.00**	**0.03**
LOLH (hours/year)	**0.00**	**0.01**

Risk Scenario Results

Resampling the wind profiles on peak load days increased the average net load peak for the top 40 net load days by 235 MW for the 10th most extreme scenario and 525 MW for the most extreme scenario. A snapshot of the top 40 daily net load peaks for each of the scenarios is shown below in Figure 8.1. In the most extreme days in the risk scenarios, the daily net load peak is over 1,000 MW higher than in the base case.

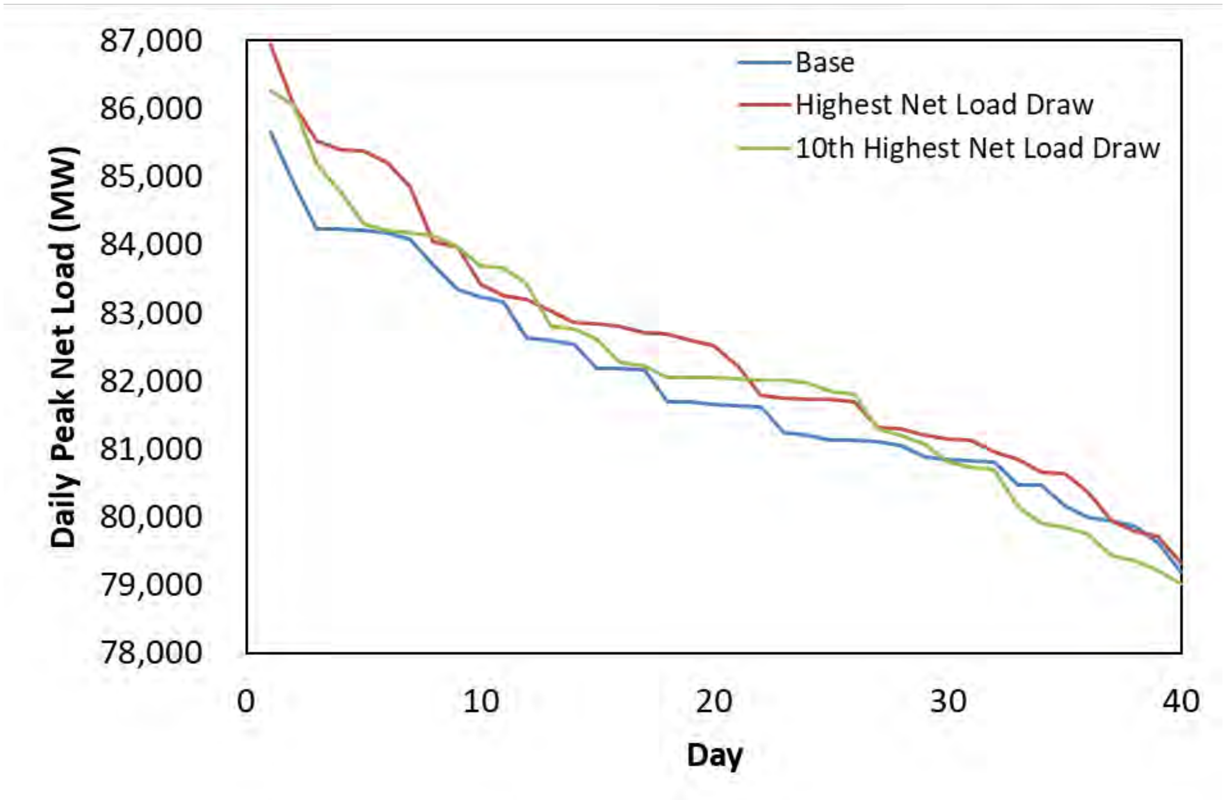

Figure 8.1 ERCOT's Load profiles for Various Assumptions

The increase in net load corresponds to a degradation of reliability when the risk scenarios are simulated. While the assumption that daily wind profiles from peak load days are fungible is not realistic, it likely provides an upper bound for the impact of wind profile uncertainty on average reliability metrics. The scenario results are compared to those found in the Base Case in Table 8.1 and highlight this upper boundary.

Table 8.1: Scenario Case Reliability Index Comparison

Reliability Index	Base Case	10th Highest Net Load Draw	Highest Net Load Draw
EUE [MWh]	12.86	31.0	64.72
LOLH [hrs/yr]	0.01	0.03	0.05

Since reliability metrics in the base case are quite low, the risk scenario impact appears quite large. EUE and LOLH in the highest net load draw scenario increase by a factor of approximately 5. However, simulating the risk scenarios at a lower reserve margin which is more consistent with industry standard reliability expectations (0.1 LOLE) suggests a smaller impact. In this case LOLH increases from .24 to .49 for the highest net load draw scenario.

Chapter 9: WECC

The Western Interconnection serves over 80 million people. The interconnection spans 1.8 million square miles in all or part of 14 states, the Canadian provinces of British Columbia and Alberta, and the northern part of Baja California in Mexico. Due to the unique geography, demography, and history, the Western Interconnection is distinct in many ways from the other North American interconnections.

Key Assessment Takeaway

WECC, like NPCC, performs a simulation for multiple different Assessment Areas. These areas all were subject to a reduction of coal-fired generation and demonstrated varying results. In some areas, this scenario greatly impacted their Reliability Indices and in others, no significant increase was observed from the Base Case results. WECC determined that the impact of a reduction of coal-fired generation on the Reliability Indices depends heavily on the current penetration of coal-fired generation in the Assessment Area, as well as the Assessment Area's ability to take on external assistance under higher demand. Such a result is not indicative for more or less coal, but that the impact of faster retirements than expected has a varying impact on the Reliability Indices in each Assessment Area.

Risk Scenario Description

The Western Electricity Coordinating Council (WECC) Regional Risk Scenario examines the impacts to resource adequacy associated with potential coal-fired generation retirements. The generation resources included in this scenario started with the LTRA resources and removed additional coal-fired generation resources that are expected to retire but do not yet have an approved decommission plan.

Coal-fired generation is a key baseload component of the Western Interconnection's resource mix but is also one of the most controversial. With the retirement or planned retirement of considerable amounts of coal-fired generation, and an increase in variable energy resources, the need to ensure sufficient capacity to reliably meet electricity demand at any given hour within the Western Interconnection is becoming more significant. This scenario specifically analyzes the reliability impacts of retiring coal plants beyond those that are being retired in the LTRA; this assessment includes coal retirements based on the best information provided by stakeholders or are mandated by state polices. This scenario also provides insights into where additional risk may occur with fewer baseload resources and examines the effects of these potential retirements to help mitigate reliability risks to the Bulk Power System (BPS).

WECC's Reliability Risk Priorities focus on four reliability concerns: Resource Adequacy and Performance, Changing Resource Mix, Distribution System and Customer Load Impacts on the BPS, and Extreme Natural Events. It would be appropriate to study any of these topics, but Resource Adequacy incorporates elements of each priority and serves as the basis for additional studies in each of these priorities. If more information is desired, please see Appendix E for the link to WECC's Western Assessment that contains more details.

Coal-fired generation has historically been a major energy resource in the Western Interconnection. However, as the generation resource mix in the Western Interconnection transitions from thermal based resources to variable generation resources, coal-fired generation will continue to be retired. This study examines the impacts to resource adequacy and planning reserve margins associated with aggressive coal-fired generation retirements.

It is anticipated that coal-fired generation retirements will continue, both in response to governmental directives and for economic reasons. For the most part these baseload resources are being replaced by high variable generation such as wind and solar. Resource adequacy planners need to understand the variability associated with wind and solar generation and incorporate probabilistic studies in the resource adequacy planning process. This assessment is focused on examining the risks to resource adequacy associated with not having enough resources to meet demand following aggressive coal-fired generation retirements.

The chart (below in Figure 9.1) shows the amount of possible coal retirements over the next ten years that were not reported in the LTRA or Prob-A base case. The years 2022 and 2024 are highlighted as the years reported in the scenario. Accumulated coal-fired capacity retirements that were included in the ProbA scenario total over 2,300 MW.

Figure 9.1: WECC's Possible Coal Retirement Capacity by Year[24]

WECC - California – Mexico (CAMX)

The CAMX subregion is a summer peaking subregion that consists of most of the state of California and a portion of Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California, which benefits the subregion as there are resources available in one area when the other is experiencing their demand peak.

Demand

The CAMX subregion is expected to peak in late August at approximately 53,400 MW for both 2022 and 2024. Overall, the CAMX subregion should expect an 100% ramp, or 26,700 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 66,000 MW, which equates to a 24% load forecast uncertainty and could peak as high as 65,000 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 50,400 MW. Under low resource availability conditions, the CAMX subregion may only have 44,300 MW to meet a 53,400 MW expected peak. The expected availability of resources on the peak hour in 2024 is 54,400 MW. Under low resource availability conditions, the CAMX subregion may only have 46,400 MW to meet a 53,400 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 45,000 MW, the low availability end of the spectrum would only see a loss of 4,000 MW, or less than 10%. Whereas, solar

[24] For further information regarding this study please use the link in Appendix E to access the WECC's Western Assessment of Resource Adequacy report.

resources total 6,500 MW, which on a low availability end of the spectrum for resource availability, could expect to lose 5,500 MW or nearly 90% of this resource.

For this scenario, there were no new coal retirements included in this subregion. However, coal retirements that occurred in the other subregions did have an impact in the amount of energy available to transfer to CAMX.

Planning Reserve Margin

Given the growing variability, a 15% margin for the CAMX area is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 40%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 11,000 MW or 20% of the expected peak demand.

Risk Scenario Results

For the CAMX region, the Reliability Indices are summarized in Table 9.1, broken out by the CA region and the MX region. The Mexico portion of the CAMX region has seen a significant increase in their demand forecast since the 2018 ProbA was published. The annual energy demand forecast for 2022 was expected at around 15,900 GWh when reported for the 2018 Prob-A. In the 2020 Prob-A, the annual energy forecast has risen to approximately 16,900 GWh, a change of approximately 6.0%. This new demand forecast coupled with the California portion of the regions inability to transfer energy after the peak hours in the evening, due to their own shortfalls, has led to a significant increase in expected unserved energy for this region. Looking at the California portion of this region, the LOLH and EUE have improved since last probabilistic assessment with large improvements by 2024.

Table 9.1: Reliability Index Comparison – CAMX

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
California Only						
EUE [MWh]	26,930	29,266	2,336	6,886	36,164	29,278
EUE [ppm]	146	159	13	27	133	106
LOLH [hrs/yr]	0.8	0.8	0	0.15	0.74	0.59
Mexico Only						
EUE [MWh]	987,786	1,392,212	416,426	2,396,090	2,991,820	595,730
EUE [ppm]	3,622	5,152	1,530	8,793	10,846	2,053
LOLH [hrs/yr]	21	31	10	55	70	15

Annual Demand at Risk (DAR)[25]

In 2022, for the scenario, the CAMX subregion could experience as many as 32 hours where the 1 day in 10 years LOLE threshold of resource adequacy is not maintained, and up to 71 hours by 2024. For the base case the results were 22 and 56 hours, respectively. Given the CAMX subregion will need to rely heavily on external assistance to maintain resource adequacy, the impacts to demand at risk of the scenario came from retirements in other subregions as no coal was retired in CAMX.

Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for CAMX causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the CAMX subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

[25] WECC distinguishes the term Loss-of-Load Hours (LOLH) as “Demand at Risk (DAR)”. The two terms here are synonymous

Energy at Risk

In 2022, about 5,200 per million MWh of energy[26] is at risk in the scenario case and grows to nearly 11,000 per million MWh by 2024. In the base case, the results were 3,700 and 8,800 per million MWh, respectively. For the 32 hours of potential demand at risk in the scenario results, this would equate to approximately 162 per million MWh, on average, in 2022. For the 71 hours of potential demand at risk in the scenario results, this would equate to approximately 155 per million MWh, on average, in 2024.

WECC - Southwest Reserve Sharing Group (SRSG)

The SRSG subregion is a summer peaking area that consists of the entire states of Arizona and New Mexico and a portion of the states Texas and California.

Demand

The SRSG subregion is expected to peak in mid-July at approximately 26,100 MW in 2022 and 26,900 MW in 2024. Overall, the SRSG subregion should expect an 93% ramp, or 12,600 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 29,600 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 30,600 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 29,600 MW. Under low resource availability conditions, the SRSG subregion may only have 24,100 MW to meet a 26,100 MW expected peak. The expected availability of resources on the peak hour in 2024 is 29,200 MW. Under low resource availability conditions, the SRSG subregion may only have 24,200 MW to meet a 26,900 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Although baseload resources account for roughly 25,000 MW of availability, the low availability end of the spectrum would only see a loss of 3,100 MW. Whereas, solar resources total 1,400 MW of availability, but on a low availability end of the spectrum, they could expect to lose 600 MW or nearly half of this resource.

For this scenario, there were approximately 400 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 16% margin for the SRSG subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 27%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 3,500 MW or 13% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the SRSG region, the Reliability Indices are summarized in Table 9.2.

Table 9.2: Reliability Index Comparison – SRSG

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
EUE [MWh]	11	212	201	81	437	356
EUE [ppm]	0.106	2.05	1.90	0.75	4.03	3.28
LOLH [hrs/yr]	0.001	147	146	0.004	22	22

[26] Any reference to "per million MWh of energy" can be translated to a EUE in total MWh in the tables provided for each region.

Annual Demand at Risk

In 2022, for the scenario, the SRSG subregion could experience as many as 14 hours where the 1 day in 10 years LOLE threshold of resource adequacy is not maintained, and up to 22 hours by 2024. For the base case the results were less than an hour in both years. The impacts of the scenario came from the 400 MW coal retirement as well as impacts from external assistance in other subregions.

Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for SRSG causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the SRSG subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 2 per million MWh of energy is at risk in the scenario case and grows to nearly 4 per million MWh by 2024. In the base case, the results were less than 1 per million MWh for both years.

WECC - Northwest Power Pool – United States (NWPP-US)

The Northwest Power Pool – US subregion consists of the northern US and central portions of the Western Interconnection. This subregion is both summer and winter peaking depending on location. The area covers all the states of Washington, Oregon, Idaho, Nevada, Utah, Colorado, and Wyoming as well as portions of the states of Montana, California, South Dakota, and Nebraska.

Demand

The NWPP-US subregion is expected to peak in late-July at approximately 65,000 MW in 2022 and 66,100 MW in 2024. Overall, the NWPP-US subregion should expect an 81% ramp, or 29,100 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 73,700 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 75,500 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 and 2024 is 81,300 MW. Under low resource availability conditions, the NWPP-US subregion may only have 58,700 MW to meet a 65,000 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Although baseload resources account for roughly 50,200 MW , the low availability end of the spectrum would only see a loss of 8,800 MW. Whereas, solar resources total 3,600 MW of availability, but on a low availability end of the spectrum , they could expect to lose 2,000 MW or over half of this resource.

For this scenario, there were approximately 1,100 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 15-21% margin for the NWPP-US subregion is close to the median level of reserve margin needed to maintain reliability, it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 18,200 MW or 28% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results
For the SRSG region, the Reliability Indices are summarized in Table 9.3.

Table 9.3: Reliability Index Comparison – NWPP-US						
Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
EUE [MWh]	12,799	14,681	1,882	248,573	274,091	25,518
EUE [ppm]	33	38	5	622	686	64
LOLH [hrs/yr]	0.25	0.28	0.03	4.4	6.2	1.8

Annual Demand at Risk
In 2022, for the scenario, the NWPP-US subregion could experience less than one hour where the one day in ten years LOLE threshold of resource adequacy is not maintained and just over 6 hours by 2024. For the base case the results were less than an hour in 2022 and 4 hours in 2024. The impacts of the scenario came from the 1,100 MW coal retirement as well as impacts from external assistance in other subregions.

Hours at Risk
A system wide high demand scenario would eliminate much of the external assistance available for NWPP-US causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the NWPP-US subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk
In 2022, about 37 per million MWh of energy is at risk in the scenario case and grows to nearly 685 per million MWh by 2024. In the base case, the results were 32 and 621 per million MWh respectively. For the 6 hours of potential demand at risk in the scenario results, this would equate to approximately 110 per million MWh on average in 2024.

WECC – Alberta & British Columbia (WECC-AB) & (WECC-BC)
The WECC-AB subregion covers the Alberta province of Canada while the WECC-BC subregion covers the British Columbia province. Both subregions are winter peaking.

Demand
The WECC-AB subregion is expected to peak in early-February at approximately 9,200 MW in 2022 and 2024. Overall, the WECC-AB subregion should expect an 30% ramp, or 2,100 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 9,500 MW, which equates to a 3% load forecast uncertainty.

The WECC-BC subregion is expected to peak in mid-January at approximately 9,300 MW in 2022 and 9,600 MW in 2024. Overall, the WECC-BC subregion should expect a 49% ramp, or 3,000 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 10,000 MW, which equates to an 11% load forecast uncertainty.

Resource Availability
In the WEC-AB subregion the expected availability of resources on the peak hour in 2022 is 13,300 MW and 11,000 MW in 2024. Under low resource availability conditions, the WECC-AB subregion may only have 12,000 MW to meet a 9,200 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 12,300 MW, the low availability end of the spectrum would only see a loss of 500 MW. Whereas, wind resources total 700 MW of availability, but on a low availability end of the spectrum, they could expect to lose all this resource.

In the WECC-BC subregion the expected availability of resources on the peak hour in 2022 and 2024 is 12,900 MW. Under low resource availability conditions, the WECC-BC subregion may only have 10,600 MW available to meet a 9,300 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 1,000 MW, the low availability end of the spectrum would only see a loss of 100 MW or 10%. Whereas, hydro resources total 11,800 MW, but on a low availability end of the spectrum, they could expect to lose 2,100 MW of this resource or about 20%. For this scenario, there were approximately 800 MW of additional coal retirements included in the WECC–AB subregion, zero in WECC-BC.

Planning Reserve Margin

Given the growing variability, a 15% margin for the WECC-AB subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum needed for all hours. The highest reserve margin needed is expected to be around 22%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 1,700 MW or 19% of the expected peak demand.

Given the growing variability, a 15% margin for the WECC-BC subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%,which equates to approximately 2,800 MW or 31% of the expected peak demand.

As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the scenario of both Canada subregions showed no expected LOLH or EUE. For the Canada subregions, the coal resource portion of the generation portfolio is small, and removal of these resources had little to no impact on the resource adequacy of these subregions. This is based on the sum Table 9.4.

Table 9.1: Reliability Index Comparison – Alberta and British Columbia

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
Alberta						
EUE [MWh]	0	0	0	0	0	0
EUE [ppm]	0	0	0	0	0	0
LOLH [hrs/yr]	0	0	0	0	0	0
British Columbia						
EUE [MWh]	19	0	-19	8	0	-8
EUE [ppm]	0.323	0	-0.323	0.137	0	-0.137
LOLH [hrs/yr]	0.001	0	-0.001	0.001	0	-0.001

Appendix A: Assessment Preparation, Design, and Data Concepts

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Assessment Data Questions

Please direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the *2020 NERC Probabilistic Assessment*[27]. However, extensive reproduction of tables and/or charts will require permission from NERC Staff and PAWG Members:

NERC Probabilistic Assessment Working Group (PAWG) Members

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[27] NERC_LTRA_2020.pdf

Appendix B: Description of Study Method in the ProbA

Descriptions and assumptions of each Region's probabilistic model are detailed in the sections below. Where a region is not listed, information was not provided at time of publication, but may be provided through contact via information listed in Appendix A.

MRO - MISO

General description

MISO utilized the Strategic Energy Risk Valuation Model (SERVM) to perform the 2020 ProbA base case and scenario. 30 historic weather years were modeled with 5 different economic uncertainty multipliers and 125 outage draws resulting in 18,750 unique load/outage scenarios being analyzed. In SERVM the MISO system was represented as a transportation model with each of MISO's 10 Local Resource Zones (LRZ's) modeled with their respective load forecasts and resource mixes. The LRZ's were able to import and export energy with each other within the model and the results of the study were aggregated up to the MISO level.

Demand & LFU

To account for load uncertainty due to weather, MISO modeled 30 unique load shapes based on historic weather patterns. These load shapes were developed using a neural-net software to create functional relationships between demand and weather using the most recent 5 years of actual demand and weather data within MISO. These neural-net relationships were then applied to the most recent 30 years of weather data to create 30 synthetic load shapes based on historic weather. Finally, the average of these 30 load shapes was scaled to the 50-50 forecasts from MISO's Load Serving Entities (LSE's).

To capture economic uncertainty in peak demand forecasts, MISO modeled each of the 30 load shapes with 5 different scalars (-2%, -1%, 0%, 1%, 2%). This resulted in 150 unique load scenarios (30 load shapes X 5 uncertainty scalars) being modeled.

Thermal Resources

All thermal resources in MISO were modeled as 2-state units i.e., either dispatched to full installed capacity or offline. Units with at least 1 year of operating history were modeled with their actual EFORd based on GADS data (up to 5 historic years). Units with insufficient operating history to determine an EFORd were assigned the class average EFORd.

Wind & Solar

Wind units were modeled with monthly ELCC values which can be found in MISO's 2021-22 PY LOLE Study Report. Solar resources were modeled at 50% of installed capacity. Both wind and solar were treated as a net-load reduction within the model.

Hydroelectric

Hydro units in MISO were modeled as a resource with an EFORd except for run of river units. These were modeled at their individual capacity credit which is determined by the resource's historic performance during peak hours.

Demand-side resources

Demand Response was modeled as dispatchable call limited resources. These resources were only dispatched when needed during emergency conditions to avoid shedding load. Energy Efficiency resources were modeled as load modifiers which were netted from the load within the model.

Transmission

Capacity Import Limits (CIL) and Capacity Export Limits (CEL) were modeled for each of the 10 LRZ's. If a LRZ was expected to be unable to meet its peak demand, then that zone would import capacity up to its CIL provided there was sufficient exports available from other zones.

MRO - SaskPower

General description

Saskatchewan utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE).

Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance, and outages are included in the model. The model simultaneously considers many types of randomly occurring events such as forced outages of generating units. Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 34.2 % and 30.0 %, for years 2022 and 2024 respectively. EUE calculated for base case is 80.4 MWh and 26.4 MWh for the years 2022 and 2024, respectively. LOLH follows a similar pattern to EUE.

Demand & LFU

This reliability study is based on the 50:50 load forecast that includes data such as annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model forecasted industrial load data, and weather normalization model.

The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses. Load Forecast Uncertainty is explicitly modeled utilizing a seven-step normal distribution with a standard deviation of $\pm$ 3%, 5% and 10%.

Thermal Resources

Natural gas units are typically modeled as a two-state unit so that gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as a three-state unit. Coal unit can be at a full load, a derated forced outage or a full forced outage state. Forecast derated hours are based on the percentage of the time the unit was derated out of all hours, excluding planned outages, based on the 5-year historical average. Generally, we use UFOP when forecasting reliability for the gas turbine units and FOR/DAFOR for the Steam units.

Wind & Solar

For reliability planning purposes, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand. Two methods were utilized to carry out the analysis for determining wind capacity credit. First method approximates the Effective Load Carrying Capability (ELCC) of the wind turbines by determining the wind capacity during peak load hours of each month by looking at historical wind generation in those hours. A period of 4 consecutive hours was selected and the actual wind generation in those 4 hours was used to determine the ELCC of the wind turbines. The median capacity value of wind generation in those 4 hours of each day of the month is calculated and is converted to a percent capacity by dividing that number by the maximum capacity of the wind turbine. Another method to estimate the ELCC was also utilized by looking at the top 1%, 5%, 10% and 30% of load hours in each month. Using these methods, we then looked at the lowest averages in each of the winter and summer months to come up with the wind capacity credit value.

Currently, Saskatchewan has low penetration level of Solar resources and most of it is Distributed Energy Resource (DER), which is netted off the load forecast.

Hydroelectric

Hydro generation is modeled as energy limited resource and the annual hydro energy is calculated based on the historical data that has been accumulated over the last 30 plus years. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy are then scheduled to reduce the peak loads as much as possible.

Demand-side resources

Controllable and Dispatchable Demand Response Program*:* Demand Response is modelled as an Emergency Operating Procedure by assigning a fixed capacity value (60 MW) and thus configured as a negative margin state for which MARS evaluates the required metrics. An Emergency Operating Procedure is initiated when the reserve conditions on a system approach critical level.

Energy provided from Energy Efficiency (EE) and Conservation programs is netted off the load forecast.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

MRO - SPP

General description

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million. SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Demand & LFU

Eight years (2012-2019) of historical hourly load data were individually modeled to produce 8,760 hourly load profiles for each zone in the SPP Assessment Area. In order to not overestimate the peak demand, the forecasted peak demand for 2022 and 2024 were assigned to the load shape from 2014 (the median year of the eight historical years). The other seven years were also scaled to a forecasted peak demand calculated by distributing the variance between the peaks of the non-median years to the median year.

Microsoft Excel was used to regress the daily peak values against temperatures, economics, and previous daily peak loads observed at key weather stations throughout the SPP footprint to derive the load forecast uncertainty components. The load multipliers were determined from a uniform distribution and assigned seven discrete steps with the applicable probability occurrence weighting. All seven of the load forecast uncertainty steps were modeled at or above the 50/50 peak forecast.

Thermal Resources

SPP modeled seasonal maximum net capabilities reported in the LTRA for thermal resources. Physical and economic parameters were modeled to reflect physical attributes and capabilities of the resources. Full and partial forced outages from NERC GADS data in the SPP footprint were applied on a resource basis.

Wind & Solar

SPP included wind and solar resources currently installed, under construction, or that have a signed interconnection agreement. Wind and solar resources were modeled in SERVM with an hourly generation profile assigned to each individual resource. Hourly generation is based upon historical profiles correlating with the yearly load shapes (2012 to 2019). Any resources that did not have historical shapes were supplemented by the nearest resource.

Hydroelectric

Hydro generation was modeled as energy limited resources while considering monthly hydro energy limitations calculated using historical data from 2012 to 2019. Hydro resources also considered historical daily max energies and the software dispatched by the resources as needed to maintain reliability.

Demand-side resources

Controllable and dispatchable demand response programs were modelled as equivalent thermal units with high fuel costs so that those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

Transmission

The SPP transmission system was represented as “pipes” between six zones modeled in the SPP Assessment Area. A First Contingency Incremental Transfer Capability analysis was performed outside of the SERVM software which determined transfer limits modeled between zones. All resources and loads in their respective zone were modeled as a “copper sheet” system.

NPCC- Maritimes

General description

The Maritimes assessment area is winter peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to NB. The area covers 58,000 square miles with a total population of 1.9 million.

Demand & LFU

Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts. Annual peak demand in the Maritimes area varies by +9% of forecasted Maritimes area demand based upon the 90/10 percentage points of LFU distributions.

Thermal Resources

Maritimes area uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.

Wind

The Maritimes area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the 2012–2018 period. The wind in any hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area’s actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts represents the Maritimes area’s hourly wind forecast.

Solar

Solar capacity in the Maritimes area is BTM and netted against load forecasts. It does not currently count as capacity.

Hydroelectric

Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.

Demand-side resources

Plans to develop up to 120 MW by 2029/2030 of controllable direct load control programs by using smart grid technology to selectively interrupt space and/ or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During this 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 196 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 465 MW.

Transmission

Construction of a 475 MW +/-200 kV HVDC undersea cable link (the Maritime Link) between Newfoundland and Labrador and Nova Scotia was completed in late 2017; this cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in Nova Scotia in 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern New Brunswick area.

Other

The current amount of DERs in the Maritimes area is currently insignificant at about 29 MW in winter. During this LTRA period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 184 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges, like ramping and light load conditions, will be considered and mitigation techniques investigated.

NPCC- New England

General description

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning process for the regional BPS. The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Demand & LFU

ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecast are considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of EE measures and BTM PV. Annual peak demand in the New England area varies by +11% of forecasted New England area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The seasonal claimed capability as established through claimed capability audit is used to rate the sustainable maximum capacity of nonintermittent thermal resources. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during ISO-NE defined seasonal reliability hours.

Wind

New England models wind resources use the seasonal claimed capability that is based on their historical median net real power output during seasonal reliability hours.

Solar
Most of the solar resource development in New England consists of the state-sponsored distributed BTM PV resources that do not participate in the wholesale electricity markets but reduce the real-time system load observed by ISO-NE system operators. These resources are modeled as load modifiers on an hourly basis based on the 2002 historical hourly weather profile.

Hydroelectric
New England uses the seasonal claimed capability to represent hydroelectric resources. The seasonal claimed capability for intermittent hydro-electric resources is based on their historical median net real power output during seasonal reliability hours.

Demand-side resources
On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e., treated like generators). Regional DR will increase to 592 MW by 2023 and this value is assumed constant/available thru the remainder of the assessment period.

Transmission
The area has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While several major projects are nearing completion, two significant projects remain under construction: Greater Boston and Southeastern Massachusetts and Rhode Island (SEMA/RI). The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by December 2023. The SEMA/RI project is in the early stages of construction. Additional future reliability concerns have been identified in Boston and are being addressed through a development request-for-proposal.

Other
New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

NPCC- New York
General description
The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Demand & LFU
The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the MARS model.

Thermal Resources

Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW values. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an EFORd.

Wind

New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Solar

New York provides 8,760 hours of historical solar MW profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by randomly selecting an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.

Hydroelectric

Large New York hydro units are modeled as thermal units with a corresponding multistate representation that represents an EFORd. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by randomly selecting an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.

Demand-side resources

The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance.

Transmission

The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the RPP inclusion rules. The NYISO Board of Directors selected projects under two public policy transmission planning processes: the first for Western New York and the second for Central New York and the Hudson Valley, which is known as the ac transmission need. When completed, these projects will add more transfer capability in Western New York and between Upstate and Downstate New York.

Other

The NYISO is currently implementing a 3–5-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. The FERC approved the NYISO's proposed tariff changes in January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021[28].

NPCC- Ontario

General description

The IESO is the BA for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC–New York.

[28] Distributed Energy Resources (DER) - NYISO

Demand & LFU
Each zone has an hourly load from the demand forecast, as well as a monthly load forecast uncertainty (LFU) distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability. Annual peak demand in the Ontario Area varies by +11% of forecasted Ontario area demand based upon the 90/10% points of LFU distributions.

Thermal Resources
The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Wind
Historical hourly load profiles are used to model wind generation. Wind generation is aggregated by zone. For the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

Solar
Historical hourly profiles are used to model solar generation. Solar generation is aggregated by zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production.

Hydroelectric
Hydroelectric generation is modelled using three inputs: a run-of-river component, which simulates the range of historical water availability, a maximum dispatchable capacity, and a dispatchable energy. Input values are calculated using a combination of historic hourly maximum offer data and historic hourly production data, aggregated on a zonal level. The three inputs work together to simulate the range of historical water conditions that have been experienced since market opening in 2002.

Demand-side resources
The IESO models two demand-side resources as a supply resource: demand response (DR) and dispatchable loads (DL). Both measures are modelled on an as-needed basis in MARS and will only be used when all other supply-side resources are insufficient to meet demand. DR and DL capacity is aggregated by IESO zone.

Transmission
The IESO-controlled grid is modelled using 10 electrical zones with connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in the IESO's "Transfer Capability Assessment Methodology: For Transmission Planning Studies.

NPCC- Quebec
General description
The Québec assessment area (province of Québec) is winter-peaking and part of NPCC. It covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand & LFU
The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Quebec area demand forecast average annual growth is 0.8% during the 10-year period. Annual peak demand in the Quebec area varies by +9% of forecasted Ontario area demand based upon the 90/10% points of load forecast LFU distributions.

Thermal Resources
For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.

Wind
In Quebec, wind capacity credit is set for the wintertime as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Solar
In Québec, BTM generation (solar and wind) is estimated at approximately 10 MW and doesn't affect the load monitored from a network perspective.

Hydroelectric
In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Demand-side resources
The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,730 MW on Winter 2020–2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will have an impact of 310 MW in 2020–2021, 150 MW for Winter 2021–2022, and then growing to 300 MW by 2026–2027. Another similar program for residential customers is under development and should gradually rise from 57 MW for Winter 2020–2021 to 621 MW for Winter 2030–2031.

Transmission
The Romaine River Hydro Complex Integration project is presently underway; its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015, and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) was planned be in service in 2020, but its commissioning is delayed to 2022. A new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean is now under construction phase and is planned to be in service in 2022. The project also includes adding equipment to both substations and expanding Saguenay substation.

Other
Total installed BTM capacity (solar PV) is expected to increase to more than 500 MW in 2031. Solar PV is accounted for in the load forecast. Nevertheless, since Quebec is a winter-peaking area, DERs on-peak contribution ranges from 1 MW for Winter 2020–2021 to 10 MW for Winter 2030–2031. No potential operational impacts of DERs are expected in the Quebec area, considering the low DER penetration in the area.

SERC

General description

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC utilizes General Electric (GE) Multi-area Reliability Simulation (MARS) software an 8,760-hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of fifteen interconnected areas, four of which are SERC's NERC Assessment Areas (SERC-E, SERC-C, SERC-SE, and SERC-FP). All assumptions and methods are described below and apply to the assessment areas.

Demand & LFU

For this study, annual load shapes for the seven years between 2007 and 2013 were used to develop the Base Case load model. Each of the hourly load profiles developed from the historical loads were then adjusted to model the seasonal peaks and annual energies reported in the 2020 SERC LTRA filings. Except for SERC-FP, all assessment areas are winter peaking. This study accounted for LFU in two ways. The first was to utilize seven different load shapes, representing seven years of historical weather patterns from 2007 through 2013. The second way is through multipliers on the projected seasonal peak load and the probability of occurrence for each load level. Annual peak demand varies by the following load forecast uncertainty, SERC-C: 4.75%, SERC-E: 3.95%, SERC-SE-6.11%, SERC-FP: 4.04%.

Thermal Resources

The three categories modeled in this study were thermal, energy-limited, and hourly resources. Most of the generating units were modeled as thermal units, for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. All the thermal units were modeled with two capacity states, either available or on forced outage.

The data for the individual units modeled in the SERC assessment areas was taken from the 2020 LTRA filings.

Wind & Solar

Wind and solar profiles for the units in the SERC footprint were represented using hourly generation time series. To represent the 2007-2013 meteorology, corresponding to the historical hourly load profiles, simulated production profiles were used. These profiles were extracted from available datasets from the National Renewable Energy Laboratory (NREL).

Five distinct sites were chosen for each assessment area, to represent existing wind farm locations. Similarly, five locations per SERC MRA were selected to create the solar profiles. Each site data was converted to power and aggregated to produce a typical solar shape per assessment area. To improve the robustness of the results, the study team used a 7-day sliding window method in the selection of wind and solar data.

Hydroelectric

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit is set to 20% of the nameplate capacity, which represents the run-of-river portion of the unit and is dispatched across all hours of the month. Any remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system. For hydro units, which are modeled as energy limited resources, their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load. Energy limited resources have a zero forced-outage rate.

The hydro unit data was extracted from the ABB Velocity Suite database and then adjusted to match the seasonal ratings of the units from the 2020 LTRA data. The monthly energy available is the average over the last 10 years of generation for each plant.

Demand-side resources

Demand-side resources are incorporated as an Energy Limited Resource with an annual energy megawatt hour limitation. These resources will be second in priority to thermal and variable generation to serve load. Demand response is modeled for all SERC assessment areas. For externals areas, these resources are modeled as emergency operating procedures, using the values from their LTRA submissions.

Transmission

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of area. First Contingency Incremental Transfer Capability Values for interface limits are modeled for the system. The assumption within areas is a copper sheet system (full capacity deliverability).

Texas-RE-ERCOT

General description

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas. The probabilistic assessment using Strategic Energy Risk Valuation Model (SERVM) captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables. The model performed 10,000 hourly simulations for each study year to calculate physical reliability metrics. The 10,000 hourly simulations were derived from 40 weather years, 5 load forecast multipliers, and 50 Monte Carlo unit outage draws.

Demand & LFU

ERCOT developed a 50/50 peak load forecast which represented the average peak load from 40 synthetic load profiles, each representing the expected load in a future year given the weather patterns from each of the last 40 years of history. Annual peak demand in ERCOT varied by +2.1% based upon the 90th percentile distribution. Each synthetic weather year was given equal probability of occurring. Five load forecast uncertainty multipliers were applied to each of the 40 synthetic weather years. The multipliers, which range from -4% to +4%, captured economic load growth uncertainty.

Thermal Resources

Conventional generators were modeled in detail with maximum capacities, minimum capacities, heat rate curves, startup times, minimum up and down times, and ramp rates. The winter and summer capacity ratings were based on ERCOT's LTRA Report. SERVM's Monte Carlo forced outage logic incorporated full and partial outages based on historical operations.

Wind & Solar

Wind and solar resources were modeled as capacity resources with 40 historical weather years consisting of hourly profiles which coincide with the load and hydro years. The assumed peak capacity contributions for reserve margin accounting were 63% for coastal wind, 29% for panhandle wind, 16% for other wind, and 76% for solar. The actual reliability contributions were based on the hourly modeled profiles.

Hydroelectric

Dispatch heuristics for hydro resources were developed from eight years of hourly data provided by ERCOT, applied to 40 years of monthly data from FERC 923 and ERCOT, and modeled with different parameters for each month, including total energy output, daily maximum and minimum outputs, and monthly maximum output. A separate energy-limited hydro resource was modeled to represent additional capability during emergency conditions.

Demand-Side Resources

Interruptible load and demand response resources were captured as resources with specific price thresholds at which each resource is dispatched. These resources were also modeled with call limits and Energy Emergency Alert (EEA) level.

Transmission

SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple zones using a transportation/pipeline representation. ERCOT was modeled as a single region with ties to SPP, Entergy, and Mexico to reflect historical import/export activity and potential assistance. 1,220 MW of high voltage direct current interties were included in this study.

WECC

General description

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points, with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint, with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of Variable Energy Resources (VER), and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through Loss-of-Load Probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models. Figure B.1 provides the high-level logic diagram of the processes MAVRIC performs.

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations, and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Demand & LFU

Probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the Balancing Authorities in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output is a series of hourly percentile profiles with different probabilities of occurring.

Thermal Resources

The distributions of the baseload resources, nuclear, coal-fired, gas-fired, and in some cases, biofuel and geothermal resources is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System (GADS). Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load serving area for each hour, is then computed, and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions, in that a series of hourly percentile profiles with different probabilities of occurring is produced.

Wind & Solar / Hydroelectric

Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources), is conducted like the demand calculations but with two notable differences. The first, and most significant, difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability, as weather is variable weekday or weekends. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring.

Demand-side resources

A significant portion of the controllable Demand Response/Demand-Side Management (DR/DSM) programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping – both canal and underground potable water and for irrigation. These programs are created by Load Serving Entities (LSEs) who are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in the Western Interconnection often have limitations such as limited number of times they can be called on and some can only be activated during a declared local emergency. Entities within WECC are not forecasting significant increases in controllable demand response.

Transmission

MAVRIC goes through a step-by-step balancing logic where excess energy, energy above an area's planning reserve margin to maintain the resource adequacy threshold, can be used to satisfy another area's resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas allowing the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers, external assistance from an immediate neighbor, and second order transfers, external assistance from an immediate neighbor's immediate neighbors, in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Other

Planning Reserve Margins - For each hour the demand and availability distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold planning reserve margin can be determined to identify the planning reserve margin needed to maintain a level of LOLP at or less than the threshold.

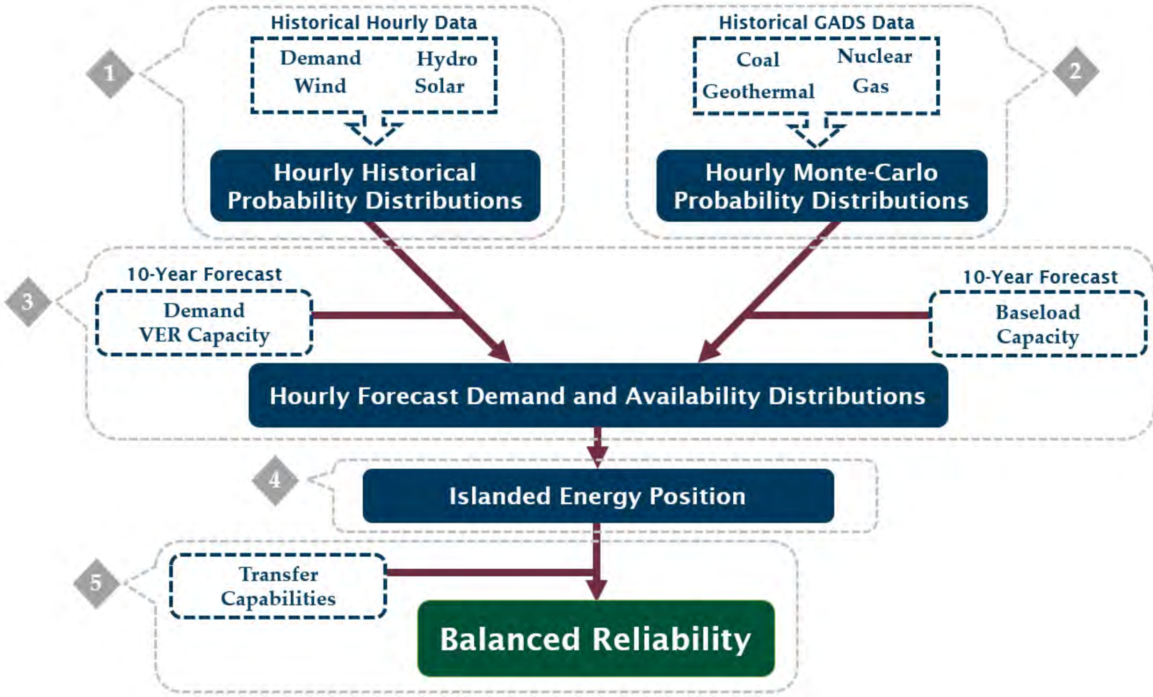


Figure B.1: MAVRIC Process Flowchart

Appendix C: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	**Name**	GE MARS	GE MARS	GE MARS	GE-MARS	GE MARS	GE MARS	SERVM	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*7	1,000*7	1,000*10*7	50000 * 7	10000	20000 x 7	28,000	50 x 40 x 5	N/A
	Total Run Time	2 hours * 72 CPUs	2 hours * 40 CPUs	50 min * 720 CPUs	3 Hours	35 min	0.5 hours	30 hours/Study Year; 35 processors	7 hours; 25 cores	N/A
Load	**Internal Load Shape**	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	07 yrs.; 2007-2013; Risk-based weighted load shapes	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak (2008)	8 historical years (2012 to 2019)	40 weather years 1980 to 2019	2004-2014
	External Load Shape	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	2007-2013 using ProbA data sheets & PJM model	N/A	Typical year 2002	None	No External Areas represented	40 weather years 1980 to 2019	N/A
	Adjustment to Forecast	Monthly Peak & Energy	Monthly Peak	Seasonal Peaks	Monthly Peaks	Monthly Peak & Energy	Monthly Peaks and Energy	Annual Peak	Annual Peak	N/A

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Load Forecast Uncertainty	Modeling	7-step Discrete Distribution	7-step Discrete Distribution. Monthly	Weather: 7 years	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps all steps at or above a 50/50 forecast	40 weather years x 5 load forecast uncertainty multipliers = 200 load scenarios	3%-97% probability distribution
	90th %ile (% above 50/50 peak)	Varies by Area; asymmetrical	2022-6%; 2024-6%	7.56% at 90%ile (1.28 Standard Deviation)	5.11%	2018-3.9% 2020-5.2%	2020-2.6%; 2018-2.6%	+5% at 99%ile	+2.1% at 90%ile	Varies by Region
	Uncertainties Considered	weather, economic, forecast	Weather, Forecast	Weather Forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	Weather, economic, forecast	Weather, Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	Percentage of Peak Load at Peak	Unknown	2022-1.9%; 2024-2.6%; Solar only	Minimal; ~1%	N/A	N/A	0	Minimal; Less than 1%	Resource	N/A
	Thermal Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Mix; Resource and Netted from Load	Resource	N/A
	Variable Generation	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Netted from Load	Resource	N/A

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Demand Management	Resource	Netted From Load	Within the load	Resource	NA	N/A	Netted from Load	Resource	N/A
Demand-Side Management	Modeling	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Operating Procedure	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchable Resource	N/A
	Load shape / Derates /FOR	N/A	N/A	Flat Seasonal	Count and Duration Limited	Reduction in Peak	None	None	Operation Count Limited	N/A
	Correlation to load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	not explicitly modeled	NA	None	Not Modeled	Dispatched based on shadow price	N/A
Variable Generation - Wind	Modeling	Resource, Fixed resource	Resource	Load Modifier	Load Modifier	Resource	Load Modifier	Resource	Resource	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	Weekly	Hourly Shape	Hourly Shape for 40 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	Consistent with load	Not Modeled	Consistent with load	Match load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	~11%	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	Ranges from 10% to 30% for Summer Peak depending on historical year and resource location	63% for coastal wind, 29% for panhandle wind, and 16% for other wind	Varies by Region
Variable Generation - Solar	Modeling	Resource	Resource	Load Modifier	Load Modifier	None	None	Resource	Resource with hourly profiles	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	N/A	Hourly Shape	Hourly for 40 years matching load profile	Hourly Shape

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	NA	N/A	Consistent with load	Yes, same weather	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	94%	MISO System Capacity Credit is 50%	NA	N/A	Ranges from 80% to 100% for Summer Peak depending on historical year	76% for Summer Peak	Varies by Region
Hydro - Electric Generation	**Modeling**	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, Dispatched after Thermal to reduce LOLE	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource, Peak Shaving	Energy Limited Peak Shaving Component	Energy Limited Peak Shaving Component and Emergency Component	Energy Limited Resource
	Energy Limits	Average	N/A	Average 10 years monthly output	Summer Months, Peak Hours 14 - 17 HE	Different below average water conditions including extreme drought	Median	8 years of historical hydro conditions were modeled 2012-2019	40 years of historical hydro conditions were modeled for 1980-2019	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Model scheduled	Netted out based on modeling actual monthly hydro energies	Varies by Region
	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Within Capacity Derates	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	MC; 2-state	MC 2-state	MC up to 5 state	MC; Up to n-state	MC; 50 iterations of annual simulations with unique forced outage draws performed for each weather year and load forecast error	2-State 3%-97% Probability Distribution

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Energy Limits	None	None	None	None explicitly	None	None	None	None	None
	Capacity Derates	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Weekly	Used a summer capacity and a winter capacity value for each unit	Seasonal
	Planned Outages	By model, External Input	By Model	By Model	By Model	By Model	By Model & Manual Input	By Model	By Model calibrated to total historical planned outages	By Model
	Forced Outages	EFORd	5 yr. EEFORd	EFORd	5 yr. unit specific EFORd	EFORd	5-year historical average	5-year EFOR GADS Data	5-year EFOR GADS Data; Historical Events Modeled Discretely	Historical 12-year EFOR
Firm Capacity Transfers	**Modeling**	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource; Exports added as load	Import treated as load modifier	Explicitly Modeled	Not Modeled. All firm resources are modeled inside the ERCOT zone.	Explicitly Modeled
	Hourly Shape Issues	None	None	N/A	None	Weekly capacities	Hourly Load modification for a typical week.	None	N/A	N/A
	Capacity Adjustments - Transmission Limitations	None	None	N/A	None	None	N/A	N/A	N/A	N/A

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	None	Accounted for in interface limits	N/A	N/A	N/A	N/A
	Forced Outages	N/A	No	No	5 yr. unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	**Assessment Areas**	5	1	7	1	1	1	1	1	6
	Total Nodes	56	5	7	10	1	1	6	1	49
	Node Definition	Determined by potentially limiting transmission interfaces	Market-Defined Regions	Assessment Areas = Nodes	Local Resource Zone	N/A	N/A	Determined by potentially limiting transmission interfaces	N/A	Balancing Authority
	Transmission Flow Modeling in ProbA Model	Transportation/Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	Transfer Analysis Import/Export Limit for each Local Resource Zone	Transportation/ Pipeline	N/A	Transportation/Pipe and Bubble; Transmission Limits modeled between nodes	N/A	Transportation/Pipeline
	Transmission Limit Ratings	NY and Maritimes - short-term emergency; all other – normal	Short-term Emergency	normal and short-term emergency ratings	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
	Transmission Uncertainty	Selected Lines	No	No	No	No	N/A	No	N/A	No
External	**# Connected Areas**	3	4	4	7	1	3	5	3	0

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	# External Areas in Study	8	4	4	7	1	0	0	SPP; MISO LRZ 8,9,10; Mexico	0
	Total External Nodes	8	59	4	1	1	N/A	N/A	3	0
	Modeling	Detailed	Detailed and At planning reserve margin	Detailed	Less Detailed	Detailed at their Planning Reserve Margin	N/A	No external assistance above firm contracts and transmission service reservation	Detailed at their Planning Reserve Margin	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	Not Considered	Yes	Yes	Yes, regulation, spin and non-spin reserve requirements modeled. Firm load shed to maintain 1150 MW of operating reserves.	No
Operating Procedures (pre-LOL)	**Forgo Operating Reserve**	OR to 0 in all Areas except Québec and New England.	Fully	Partially or Fully, depending on input from Assessment Area	N/A	N/A	Fully	Fully	Partially	Fully
	Other	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	CPP; DCLM;	None	None	Demand Response, Emergency	None	DR and Emergency Thermal Generation from Conventional Generators	None

Appendix D: ProbA Data Forms

The forms used for the 2020 Probabilistic Assessment can be found on the NERC PAWG webpage, located at the following link:
https://www.nerc.com/comm/PC/Pages/Probabilistic-Assessment-Working-Group-(PAWG).aspx

Appendix E – Additional Assessments by Regions or Assessment Areas

This informational Appendix serves as a list of references for more detailed information on assessments or assessment methods used by Regional Entities or Assessment Areas.

NERC Webpage:
www.nerc.com
The NERC webpage contains valuable information regarding its mission. For information on its assessments, please see the Reliability Assessment and Performance Analysis page. It also contains valuable information regarding the statistics for assessing BES reliability.

NPCC:
https://www.npcc.org/content/docs/public/library/resource-adequacy/2020/2020-12-01-nerc-ras-probabilistic-assessment-npcc-region.pdf
NPCC publishes a report that contains a more detailed look at the multi-area probabilistic reliability assessment for the NPCC Region, referenced in the NERC Probabilistic Assessment and this year's regional risk scenario.

SERC:
serc1.org.
SERC publishes many different assessments that can be found in the link to their main webpage above. Please use the contact information in Appendix A for any questions.

WECC:
WECC's WARA Part 1.
WECC performed a separate assessment that contains more details on how the possible coal retirements in their region were selected and can affect their system's reliability.

WECC is also working on developing a portion of their webpage to provide educational materials on how they perform their probabilistic assessments and will work as a great educational material upon its completion.

MISO:
https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf
MISO performs a Loss of Load Expectation study on an annual basis as part of their Resource Adequacy construct.

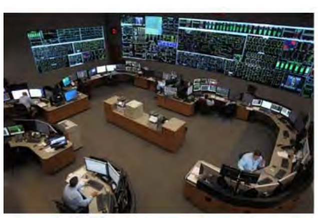
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2020 Probabilistic Assessment

Regional Risk Scenario Sensitivity Case

June 2021

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Commented [JS1]: From Wayne Guttormson: "Report was an interesting read, content was good, and chapter structure was good."

Commented [JS2R1]: Thanks for your comment.

Commented [JS3]: Page numbering is off starting with Page 9---MISO

Commented [JS4R3]: Updated the ToC formatting field to fix.

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council

FRCC

MRO – Midwest Reliability Organization

MRO-SaskPower

MRO-Manitoba Hydro

MISO

NPCC – Northeast Power Coordinating Council

NPCC-New England

NPCC-Maritimes

NPCC-New York

NPCC-Ontario

NPCC-Québec

RF – ReliabilityFirst

PJM

SERC – SERC Reliability Corporation

SERC-East

SERC-North

SERC-Southeast

SERC-FP

SPP RE – Southwest Power Pool Regional Entity

SPP

Texas RE – Texas Reliability Entity

Texas RE-ERCOT

WECC – Western Electricity Coordinating Council

WECC-BC

WECC-AB

WECC-RMRG

WECC-CA/MX

WECC-SRSG

WECC-NWPP-US

Executive Summary

~~Sensitivity results were varied across the study and dependent on their underlying assumptions. In some Assessment Areas such as Manitoba Hydro, SaskPower, PJM and certain Areas of NPCC, the study demonstrated that the risks were not significant, did not impact the probabilistic indices, or could be mitigated using preventive planning and operating measures. Other Assessment Areas noted potential risks if the chosen scenario were to materialize under the sensitivity assumptions. SPP determined Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) increases in their scenario, mostly occurring on or around the peak hour. SERC also noted low to moderate increases in their Loss of Load (LOL) indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that in many regions across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the amount of available external assistance between Assessment Areas and the penetration of coal resources in their respective portfolios. High level results of the Regional Risk Scenarios performed by Assessment Area can be found in Table ES.1~~

Over the past decade, variable energy resources are steadily replacing conventional forms of generation. To effectively assess industry plans with changing resource mixes, NERC has increasingly used probabilistic assessments as a tool to identify potential reliability risks. ~~as the industry plans resource mixes more dependent on variable energy resources and as conventional forms of generation are steadily replaced.~~ With various resource portfolios and distinct plans to meet electricity reliability requirements across the Bulk Electric System (BES) and Bulk Power System (BPS), the NERC Probabilistic Assessment Working Group (PAWG) ~~(Probabilistic Assessment Working Group)~~ recognizes that each region may have unique risks to consider and assess. This report describes the assessments of Regional Risk Scenarios ~~encouraged regional flexibility in the 2020 ProbA Sensitivity Case by developing a Regional Risk Scenarios model~~. This model allowed system planners to more closely study area-specific reliability risks and their uncertainties by using probabilistic methods. It is important to recognize that the BES (and by extension the BPS), across the six NERC Regions and Assessment Areas, is diverse in terms of planning and operations processes, as well as their associated risks. The assessment utilized a comprehensive and peer-review process for each Assessment Area's respective methods, assumptions, and results.

The Sensitivity Case scenarios include the following:

- MISO (MRO) – Increased demand response as a percentage of the overall resource mix
- Manitoba Hydro (MRO) – Variations in low water conditions with external assistance limitations
- SaskPower (MRO) – Impact of low hydro conditions on its system reliability
- SPP (MRO) – Low wind resource output with an increase in conventional generation forced outages
- NPCC – Planned/expected future capacity or resources may not materialize
- PJM (RF) – Planned/expected future capacity or resources may not materialize
- SERC – Impact of planned maintenance outage on system risk
- ERCOT (TRE) – Impacts of a difference in the realized frequency of high load and low wind output events
- WECC - Impacts to resource adequacy associated with potential coal-fired generation retirements.

Regions were requested to compare the purported risk factor results in the Probabilistic Assessment (ProbA) Sensitivity Case to the ProbA Base Case results from the 2020 NERC LTRA. These comparisons between the Base and Sensitivity Cases, combined with the trending results compared from the 2018 ProbA (found in the 2018 LTRA), provide a complete analysis to better understand underlying uncertainties and benchmark system risks. At regional discretion, the scenarios intentionally stressed the assumptions to study their associated impacts on the probabilistic indices. Although mitigation efforts were not the intended focus of the study, some regions provided rationale on expected methods to mitigate against that chosen risk.

Commented [JS5]: From Wayne Guttormson: "Recommendations in the Exec Summary for industry are good. Is there a recommendation that is being made within the scope of the RSTC?"

And

"Depending on the audience for the report, some chapters could use some further discussion on how to interpret the changes in the probabilistic indices identified (LOLH, LOLE, EUE, etc.). "

Commented [JS6R5]: No, there are no entity specific recommendations in the document, and no other recommendations above what is scoped in the PAWG.

A footnote has been added to help determine LOLH and EUE. No further edits in the chapters made based on Assessment Area contributions.

Commented [AL7]: Is this first paragraph necessary? If so, maybe it should be in a Key findings box?

Commented [JS8R7]: Moved to a new section entitled "Key Findings" before Table ES.1

Commented [JS9]: Need to define acronyms.

Commented [JS10R9]: Added acronym definitions here.

Commented [JU11]: First time spell out.

Commented [JS12R11]: Spelled out the acronym.

Commented [JU13]: First time spell out

Commented [JS14R13]: Spelled out the acronym.

Commented [AL15]: I would love to see the Key Takeaway repeated in the executive summary for each region.

Commented [JS16R15]: The Key Assessment Takeaway boxes are summarized in a single sentence per Assessment Area in the new "Key Findings" section.

Key Findings

Sensitivity results were varied across the study and dependent on their underlying assumptions. In some Assessment Areas such as Manitoba Hydro, SaskPower, PJM, and all Assessment Areas of NPCC, the study demonstrated that the risks were not significant, did not impact the probabilistic indices, or could be mitigated using preventive planning and operating measures. Other Assessment Areas noted potential risks if the chosen scenario were to materialize under the sensitivity assumptions. SPP determined Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE)[1] increases in their scenario, mostly occurring on or around the peak hour. SERC also noted low to moderate increases in their Loss of Load (LOL) indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that in many regions across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the amount of available external assistance between Assessment Areas and the penetration of coal resources in their respective portfolios. High level results of the Regional Risk Scenarios performed by Assessment Area can be found in Table ES.1. To understand the results in Table ES.1, see each Assessment Area's section of the report for the comparison of these values to the base case Probabilistic Assessment results as well as any additional references provided in Appendix E.

Table ES.1: Summary of Regional Risk Scenario for Each Assessment Area[2]

Assessment Area	2022 Expected Unserved Energy ~~Unserved~~ [MWh/yr~~.~~]	2022 Loss of Load Hours [hrs/yr]~~[hrs./yr.]~~	2024 Expected Unserved Energy ~~Unserved~~ [MWh/yr~~.~~]	2024 Loss of Load Hours [hrs~~.~~/yr~~.~~]
MRO				
MISO[3]	N/A	N/A	27.69	0.24
Manitoba Hydro	45.13	1.79	0.05	0.06
SaskPower	319.20	3.50	59.70	0.60
SPP	N/A	N/A	72.60	0.11
NPCC				
New England	5.30	0.01	88.10	0.14
Maritimes	4.16	0.08	6.72	0.13
New York	0.68	0.00	13.90	0.05
Ontario	0.09	0.00	79.96	0.14
Québec	0.00	0.00	0.00	0.00
RF				
PJM	0.00	0.00	0.33	0.00
SERC[4]				
Central	N/A	N/A	12.20	0.02
East	N/A	N/A	517.40	0.57

[1] For information on interpreting the values of EUE and LOLH used to evaluate the scenarios, see NERC PAWG Probabilistic Adequacy and Measures Report

[2] An "N/A" is denoted where the Assessment Area chose not to perform the Risk Scenario for the optional study year.

[3] MISO's scenario has many different amounts of Demand Response entered in 2024. This table uses the maximum Demand Response added in their scenario. ~~To further understand these results, readers are advised to read MISO's Chapter to better understand these numbers.~~

[4] SERC performed an extensive stressing of their system to start at a higher LOLE than from the Base Case and performed many different multiplications of their capacity on maintenance. This table uses the maximum reported EUE and LOLH at the extreme scenario. ~~Readers are extremely encouraged to read SERC's Chapter to understand these numbers.~~

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Commented [AL17]: Is this first paragraph necessary? If so, maybe it should be in a Key findings box?

Commented [JS18R17]: Moved to a new section entitled "Key Findings" before Table ES.1

Commented [JS19]: Need to define acronyms.

Commented [JU21]: First time spell out.

Commented [JS22R21]: Spelled out the acronym.

Commented [JS20R19]: Added acronym definitions here.

Commented [NA23]: Suggest deleting "." After "hrs" and "yr" – not needed

Commented [JS24R23]: Agreed. Change made as proposed.

Commented [JG25]: Per the footnote, it might be better to have a similar sentence provided for the SERC footnote, "Readers are extremely encouraged to read SERC's Chapter to understand these numbers."

Commented [JS26R25]: Text added to mention to read the specific Assessment Area chapter to understand the details surrounding the numbers above the table. Removed all individual references for a single, concise approach.

Table ES.1: Summary of Regional Risk Scenario for Each Assessment Area[2]

Assessment Area	2022		2024	
	Expected Unserved Energy ~~Unserved~~ [MWh/yr]	Loss of Load Hours [hrs/yr]~~[hrs./yr.]~~	Expected Unserved Energy ~~Unserved~~ [MWh/yr]	Loss of Load Hours [hrs/yr]
Southeast	N/A	N/A	7.50	0.01
Florida Peninsula	N/A	N/A	513.30	0.52
Texas RE				
ERCOT[5]	N/A	N/A	64.72	0.05
WECC				
BC	0.00	0.00	0.00	0.00
AB	0.00	0.00	0.00	0.00
CA/MX[6]	1,005,716	32.00	2,402,976	71.00
SRSG	212	14.00	437	22.00
NWPP-US	14,681	Less than 1	274,091	6.00

Commented [NA23]: Suggest deleting "." After "hrs" and "yr" – not needed

Commented [JS24R23]: Agreed. Change made as proposed.

Recommendations

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With an increasing amount of uncertainty expected on the BPS with regional resource transitions, the PAWG recommends further increasing the use of probabilistic methods and scenarios to adequately study the reliability risks and to determine the sensitivity of those risks for various scenarios. The PAWG also recommends increasing the coordination between industry operations and planning personnel to further develop ~~develop enhanced and more complex scenario~~ assumptions for probabilistic reliability assessments. These collaborations and studies could better inform, strengthen, and reinforce the fundamental BPS planning and operations processes to meet future reliability needs.

Commented [WP27]: I have no idea what does "enhanced" or "more complex" means. Can you provide an example or two?

Commented [JS28R27]: Modified to commenter's satisfaction.

[5] ERCOT's scenario contained many different load draws. The one that produced the highest EUE and LOLH are presented in this table.

[6] See the Western Assessment in Appendix E for detailed assumptions, findings, and recommendations over what is reported in this document.~~information on this scenario run as well as Chapter 9 for a detailed meaning of the results.~~

Introduction

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and support probabilistic resource adequacy efforts of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force (PAITF)[7] with the Probabilistic Assessment Improvement Plan.[8] Specifically, the group researches, identifies and details probabilistic enhancements applied to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[9] and the Reliability Issues Steering Committee (RISC) report[10] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

NERC regularly utilizes reliability assessments to objectively evaluate the reliability of the North American Bulk Power System (BPS). On a biennial basis, the NERC PAWG performs a Probabilistic Assessment (ProbA) to supplement the annual deterministic NERC Long Term Reliability Assessment (LTRA) analysis. The ProbA calculates monthly Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH)[11] indices for years 2 (Y2) and 4 (Y4) of the 10-year LTRA outlook (2022 and 2024 for the 2020 LTRA[12], respectively) and contains two studies: a Base Case and a Sensitivity Case. The two differ in that the Base Case contains assumptions ~~for~~ under normal, anticipated operating conditions, and study results were each peer-reviewed by the NERC PAWG, NERC RAS and NERC Reliability and Security Technical Committee (RSTC) to ensure comparisons made in the LTRA can be applied~~made~~ across entities. Complete details and underlying assumptions of the 2020 ProbA Base Case analysis were included in the published 2020 LTRA in December 2020. The Sensitivity Case provides NERC a way to characterize more "what-ifs" in terms of the probabilistic methods used in each region ~~that can provide a much different result depending on~~. For the 2020 ProbA Sensitivity Case, the PAWG developed a Regional Risk Scenarios approach specific to each assessment area. Each region and assessment area has varied resource ~~portfolios~~ mixes, leading to different study focuses ~~which differentiates changing reliability drivers~~ between assessment areas. The assessment areas identified and studied respective risk factors to better understand ~~drive deeper understandings of~~ the reliability implications across all hours (instead of just the peak hour) using probabilistic methods. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across the BPS. Y2 and Y4 indices were reported for the Base Case study. For the Sensitivity Case, assessment areas were required to perform the analysis on Y4 and Y2 was optional.

Chapters in this assessment are primarily divided by the Regional Risk Scenario chosen for the 2020 ProbA. While Regional Risk Scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences. These results are used to inform system planners and operators about potential emerging reliability risk. The PAWG intends to utilize these study results ~~for use~~ in future probabilistic resource adequacy studies (such as trending applications) to develop further guidance for future work activities, ~~. W~~where~~. Where~~ prominent, key points and takeaways are called out.

[7] Probabilistic Assessment Improvement Task Force (PAITF)
[8] Probabilistic Assessment Improvement Plan
[9] See Focus Areas 1 and 4: ERO Enterprise Long-Term Strategy
[10] See Risk 1: Reliability Issues Steering Committee (RISC)
[11] NERC PAWG Probabilistic Adequacy and Measures Report
[12] NERC_LTRA_2020.pdf

Commented [JS29]: From Wayne Guttormson: "Suggest the risk scenarios could also be discussed in relation to the *ERO Risk Priorities Report* - Grid Transformation, Extreme Natural Events, Security Risks, and Critical Infrastructure Interdependencies. This could be an improvement for a future version."

Commented [JS30R29]: PAWG agrees that this could be a consideration for future reports but not in this one.

Commented [WP31]: Is something needed for the ending?

Commented [JS32R31]: Clarified sentence to commenter's satisfaction.

Commented [JS33]: From David Jacobson: "Page ix "The Sensitivity Case provides NERC a way to characterize more "what-ifs" in terms of the probabilistic methods used in each region that can provide a much different result depending on." Depending on what? I think a thought is missing here."

Commented [JS34R33]: Clarified sentence per comment above.

Commented [JS35]: Rephrased to address Hydro One's comment.

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Chapter 1: MRO - MISO

MISO is a summer peaking system that spans 15 states and consists of 36 Local Balancing Areas which are grouped into 10 Local Resource Zones (LRZs). For the 2020 NERC Probabilistic Assessment, MISO utilized a multi-area modeling technique for the 10 LRZs internal to the MISO footprint. Firm external imports as well as non-firm imports were also modeled within the cases.

Key Assessment Takeaway

MISO found that as the percent of Demand Response resources increased in their system, their Reliability Indices could double or triple. This is due to the need to call on Demand Response more and earlier in the year, leaving them unavailable for future calls in the year.

Risk Scenario Description

For the 2020 Probabilistic Assessment Risk Scenario, MISO performed a sensitivity analysis that examined the effects of increasing Demand Response (DR) resources as a percentage of the overall resource mix. Over the past several years the amount of DR in MISO has been steadily increasing. For DR to qualify as a capacity resource in MISO, it must be available for a minimum of 5 calls per year and 4 hours per day. These minimum dispatch requirements make up much of the DR that currently participates in MISO's capacity market.

MISO conducts a Loss of Load Expectation (LOLE) study annually to determine the amount of reserves required to meet the 1-day-in-10-years LOLE standard. In this study, each individual DR resource in MISO is modeled with their registered dispatch limits. There are cases in that analysis where all the available dispatches for DR would be used and load shed occurred as a result. This discovery prompted a desire to further investigate the effect that dispatch limited DR has on reliability ~~hence this risk scenario~~. See Appendix E for ~~where~~ details on where to find the report.

To perform this analysis, MISO began from the 2024 base case ProbA scenario. DR, totaling 5,000 MW, ~~DR~~ was then added to the resource mix in increments of 1,000 MW evenly distributed among the 10 LRZs while simultaneously removing 1,000 MW of generation. Doing this allowed MISO to examine how the risk changes from the base case as DR makes up an increasing amount of reserves.

Base Case Results

MISO's Base Case results, reproduced here, show a small amount of EUE and LOLH which is consistent with past ProbA results. Since MISO is a summer peaking system, most of the risk occurs during the summer months (June – Sept) as expected. However, there are cases where off-peak risk occurs due to certain zones being import limited[13] during periods of high planned outages.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**21.6%**	**17.6%**
Reference	**18.0%**	**18.0%**
~~ProbA Forecast Operable~~	~~**17.9%**~~	~~**17.8%**~~
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**27.3**	**14.3**
EUE (ppm)	**0.038**	**0.020**
LOLH (hours/year)	**0.196**	**0.085**

Risk Scenario Results

Currently, DR makes up roughly 4.9% of the total resource mix in MISO. This percentage is reflected in the Base Case results and served as a starting point for the Risk Scenario study. From that starting point, an additional 5,000 MW of DR was added to the system in increments of 1,000 MW ~~at a time which nearly doubled the amount of DR as a percentage of total resources. The~~. The percentage of DR to the overall resource mix can be found in Table 1.1.

[13] Detailed studies on these hours are found in the report linked in Appendix E

Commented [JS36]: From Arun Narang (Hydro One): "Broken sentence?"

Commented [JS37R36]: Added clarity to sentence meaning.

Commented [JU38]: Does this really reflect how DR would be called upon in real-time by operations? Is it market based? If it is this may not be the case and could happen in pockets etc.

Commented [JS39R38]: The model calls on DR in the same situations that operators would in real time. It is treated as an emergency resource and is only called upon as a last resort when all other resources have been dispatched and there is still a projected shortage.

Commented [JU40]: Are the PCs and TPs looking into this so it get mitigated? Do our studies show where these are? Can we model this and sit down with MISO and talk through the risk?

Commented [JS41R40]: Import limits are determined from a separate transfer limit analysis which and vetted through MISO's stakeholder process. Details including the constraints that drive the results are available in MISO's LOLE report which is linked in the appendix. Added footnote to help guide readers.

Commented [JU42]: What assumptions allows MISO to do this when it is an uncertain resource?

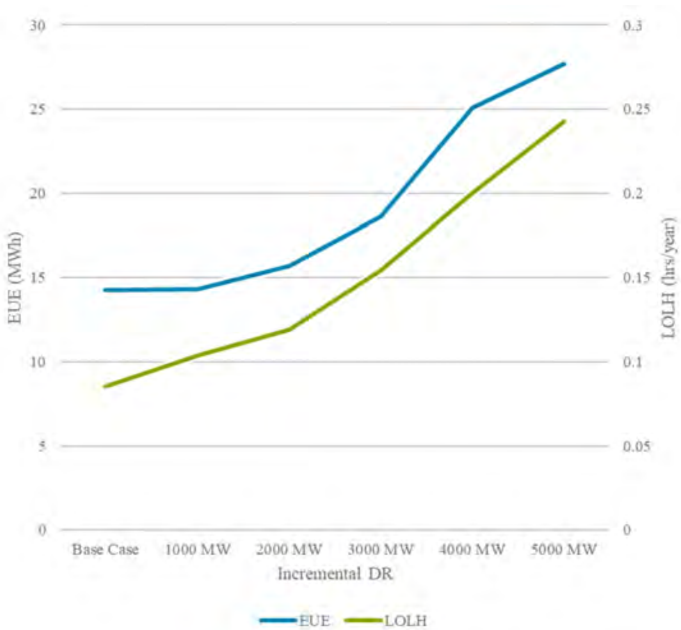
Commented [AC43R42]: Further clarification would need to be provided by MISO staff

Commented [WP44]: I would not describe that 8.1% is nearly doubled of 4.9%.

Commented [JS45R44]: Changes to the sentence removed this.

Table 1.1: Demand Response Percentage of Overall Resource Mix	
Demand Response Added [MW]	**Percent of Overall Resource Mix [%]**
Base Case	4.9
1,000	5.5
2,000	6.1
3,000	6.8
4,000	7.4
5,000	8.1

EUE and LOLH values were recorded for each iteration of increasing DR. As shown in the chart below, when DR increases as a percentage of total resources, EUE and LOLH also increase. By the time an additional 5,000 MW of DR was added, the EUE had nearly doubled and LOLH nearly tripled when compared to the Base Case. The increased risk is driven by the dispatch limits of DR. As previously mentioned, most DR in MISO is only available for 5 calls per year and 4 hours per day. As DR begins to make up more of the resources on the system, these resources most likely will exhaust their dispatch limits sooner and become unavailable for the remainder of the year. Historically, DR in MISO was credited in the capacity market solely based on its registered MW. Recently, MISO implemented enhanced accreditation rules for DR that considers dispatch limits and lead times, which will allow MISO to more effectively access the capabilities of DRs to maintain system reliability. As the region's risk profiles continue to evolve with the changing resource mix, MISO is continuously enhancing its resource adequacy planning process and is looking into sub-annual planning approach to sufficiently capture and mitigate risks across the year.



Commented [JU46]: What makes MISO believe it will? Need something to indicate this.

Commented [AC47R46]: Further clarification would need to be provided by MISO staff

Commented [JS48]: From Robert Reinmuller (Hydro One): "This seems like an opportunity to explore"

Commented [JS49R48]: Added sentences describing recent market changes to mitigate risk.

Commented [JG50]: It would be beneficial to add a statement indicating the severity of this risk and possible mitigations (similar to other Assessment Areas).

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Commented [JS51R50]: Added sentences describing recent market changes to mitigate risk.

Figure 1.1 MISO Regional Risk Scenario EUE and LOLH[14]

Commented [WP52]: I think it is important to note in the graph that the incremental DR replaces other capacity resources for those who don't read the text.

Commented [JS53R52]: Added Footnote to help explain chart.

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[14] Note that the EUE and LOLH shown here increase as DR replaces traditional generation in increments of 1,000 MW

Chapter 2: MRO – Manitoba Hydro

Manitoba Hydro (MH) system has approximately 6,~~878.9~~900 MW (nameplate) of total generation. The system is characterized by around 4,350 MW of remote hydraulic generation located in northern Manitoba and connected to the concentration of load in southern Manitoba via the Nelson River HVdc transmission system. MH also has about 1,858.4 MW of hydraulic generation distributed throughout the province. In addition, 258.5 MW of wind generation and 412 MW thermal generation are distributed in the southern part of the province. The MH system is interconnected to the transmission systems in the Canadian provinces of Saskatchewan and Ontario and the US states of North Dakota and Minnesota.

Key Assessment Takeaway

Manitoba Hydro's reliance on hydro facilities can be susceptible to low water conditions for a given year. This is mitigated by proper management of reservoirs.

The 2020 NERC Probabilistic Assessment for the MH system was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company (GE). The reliability indices of the annual Loss of Load Hours (LOLH) and the Expected Unserved Energy (EUE) for 2022 and 2024 were calculated by considering different types of generating units (thermal, hydro and wind), firm capacity contractual sales and purchases, non-firm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty and demand side management programs. The data used in the MARS simulation model are consistent with the information reported in the 2020 LTRA submittals from MH to NERC. On a winter accredited capacity basis, the resources within Manitoba are 92.76% hydro, 0.84% wind, and 6.41% thermal.

Risk Scenario Description

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance such as the water resource conditions, energy exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast, demand responses, energy efficiency and conservation programs, wind penetration and generation fleet availability.

The vast majority of MH's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2020 Assessment, MH has examined the impact of the most significant factor over the long run - variations in water conditions as detailed in the following:

1. Analyze the system as is to establish base reliability indices (Base case)
2. Variations in water conditions: model a 10-percentile low water condition and report the indices

All hydro units are modeled as Type 2 energy limited units in MARS[15]. The MARS input parameters for each hydro power plant are installed/in-service and retirement dates, monthly maximum and minimum output of each plant and monthly available energy from each plant. Each energy limited hydro unit is scheduled on a monthly basis. The first step is to dispatch the unit's minimum rating for all of the hours in the month. The remaining capacity and energy are then scheduled as needed as a load modifier during the Monte Carlo simulation.

Base Case Results

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	2024

[15] Type 2 units in the MARS program are "energy-limited units are described by specifying a maximum rating, a minimum rating and a monthly available energy", as stated in their program manual

Commented [WP54]: Why not round the capacity to 6,900 MW when the word approximately is used? How approximate can it be when it is down to .9 of a MW? Rounding it to 6,900 MW is probably consistent with the "around 4,350 MW" noted in the same paragraph.

Commented [JS55R54]: Change made as requested.

Commented [JS56]: From Robert Reinmuller: "Maybe worth indicated the % of resource mix"

Commented [JS57R56]: Added a sentence to address comment.

Commented [JS58]: From Robert Reinmuller (Hydro One): "Can we explain type 2"

Commented [JS59R58]: Added definition from GE MARS manual.

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Anticipated	**16.6%**	**16.0%**
Reference	**12%**	**12%**
~~ProbA Forecast Operable~~	~~**20%**~~	~~**20%**~~

Annual Probabilistic Indices

	2022	**2024**
EUE (MWh)	**2.7077**	**3.3831**
EUE (ppm)	**0.1072**	**0.1329**
LOLH (hours/year)	**0.0033**	**0.0039**

The base case LOLH values calculated for the reporting year of 2022 and 2024 are virtually zero. Non-zero EUE are obtained but these values are small. These results are mainly due to the larger forecast reserve margin and the increase in the transfer capability between Manitoba and US due to the addition of the new 500 kV tie line between Manitoba and Minnesota. The base case LOLH and EUE values calculated in this assessment for the reporting year of 2022 increase a bit from those zero values obtained in 2018 assessment for the reporting year of 2022. This is expected as result of modeling improvement and changes in assumptions. The most significant model improvement for 2020 Probabilistic Assessment is that Manitoba Hydro modeled seven (7) different load shapes using actual historical data to capture the uncertainties associated with load profiles and peak load forecast. In 2018 assessment, only a typical year load profile was used to model the annual load curve shape.

Risk Scenario Results

Scenario Case Summary of Results

	2022	**2024**
EUE (MWh)	**45.13**	**56.38**
EUE (ppm)	**1.7870**	**2.2150**
LOLH (hours/year)	**0.0544**	**0.0643**

Hydro flow condition is the most significant parameter that characterizes Manitoba Hydro's system resource adequacy. In the 2020 assessment Manitoba Hydro has examined variations in water conditions in the scenario analysis. Scenario analysis results show that LOLH and EUE values increase for both 2022 and 2024 when an extreme drought scenario is modeled. Water flow conditions of 10 percentile or lower tend to increase the loss of load hours and expected unserved energy. As a small winter peaking system on the northern edge of a large summer peaking system (MISO), there generally assistance available, particularly in off peak hours, to provide energy to supplement hydro generation in low flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Commented [JS60]: From Hydro One:
"What about availability? How does one account for not knowing whether neighbouring jurisdiction is able to provide support when needed?
"

Commented [JS61R60]: Deterministically, the concern is true but probabilistically, once the tie lines are modeled, the program will take care in the simulation if there is capacity available for helping each other in any particular hour. Generally, adding transmission between two systems would help improve adequacy of both systems and the MARS program could capture the impact well within the simulation. It is not assumed in the study that MH can always obtain assistance from others

Commented [WP62]: Adding additional import capability is meaningless if there is no surplus power on the other side and it could even degrade your system's LOLE if the other side is weaker. I suggest you add a sentence to describe the capacity condition on the other side. I suspect that MH is receiving assistance but the write up is not clear.

Commented [JS63R62]: Generally, adding transmission between two systems would help improve adequacy of both systems and the MARS program could capture the impact well within the simulation. It is not assumed in the study that MH can always obtain assistance from others.

Chapter 3: MRO – SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of approximately 652,000 square kilometers (251,739 square miles) with approximately 1.2 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan. SaskPower is the principal supplier of electricity in the province and responsible for serving over 540,000 customer accounts. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections

Key Assessment Takeaway

SaskPower's lower quartile hydro scenario ~~provided an~~ increases ~~in~~ the risk due to higher Reliability Indices, as expected, but did not rise significantly. Such increases can be mitigated by reliance on emergency procedures, if required.

Risk Scenario Description

SaskPower analyzed the impact of low hydro conditions on its system reliability. The low hydro forecast is based on 25 percentile hydro flow conditions. Hydro units constitute approximately 20 percent of Saskatchewan's net installed generation capacity and it hasn't experienced significantly low hydro conditions since 2001. The region consists of three main river~~s~~ systems and one river system experiencing low flow conditions doesn't necessarily indicate that the other systems would experience the same conditions. Although, there is low probability of low flow conditions experienced by all the river systems in the same year, the sensitivity scenario tests the system's resiliency ~~when having less energy to dispatch hydro units~~when the hydro units have less energy for dispatch, and subsequently limited peak load shaving capability. Furthermore, this risk scenario has become more relevant since the Saskatchewan government announced in July 2020 that it intends to pursue a $4 billion irrigation project at Lake Diefenbaker which could ~~significantly~~ impact the future water flows available for hydro generation by SaskPower by limiting the water flow, and thus energy available, for such generation.

The methodology used to derive the various hydro conditions is based on the historical hydrological records in the basin. Before using these historical hydrological records to model any flow scenarios, adjustments were applied to these records, which includes historical and present upstream water uses, ~~adjustment to the current level of development~~changes in water management, and naturalized flow records if necessary. The long-term forecasts typically use low (lower quartile), best (median) and high estimate (upper quartile) flows based on the current level of development adjusted historical records. Hydro units are modelled as Type 2 energy limited units in MARS. The median quartile hydro conditions in the base case were replaced with lower quartile hydro conditions for the sensitivity scenario.

Base Case Results

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period. The major contribution to the Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) is in the off-peak periods due to maintenances scheduled for some of the largest units.

SaskPower did further analysis changing some of the fixed unit maintenances in year 2022 and let the model schedule it automatically~~.~~ to lower system risk of loss of load.~~.~~ With changing the unit maintenances, EUE reduced

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**34.2%**	**30.0%**
Reference	**11%**	**11%**
~~Prob A Forecast Operable~~	~~**30%**~~	~~**25.7%**~~
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**80.4**	**26.4**
EUE (ppm)	**3.34**	**1.07**
LOLH (hours/year)	**0.96**	**0.28**

Commented [JS64]: From Hydro One:
"Re text in "Key Assessment Takeaway": "increase in reliability indices" means lower reliability (not increased reliability), so perhaps could be rephrased for clarity (degraded reliability; degradation of indices)
"

Commented [JS65R64]: Rephrased for clarity

Commented [WP66]: This sentence reads funny. May be modify it to say "…when the hydro units have less energy for dispatch"? Anyway, I am sure you can come up with something better.

Commented [JS67R66]: Clarity added.

Commented [WP68]: Any numerical value? I have no idea what does "significantly impact" mean. Cut water availability by 80%?

Commented [JS69R68]: Removed significantly. Addressed with other similar qualifiers.

Commented [JS70]: From Hydro One:
""Significant impact" in terms of making it worse or better?"

Commented [JS71R70]: Clarity added based on SaskPower addition.

Commented [WP72]: What is this development?

Commented [JS73R72]: Clarified the sentence to commenters satisfaction.

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by more than 50 percent. Most of the maintenances are scheduled during off-peak periods and can be rescheduled to mitigate short–term reliability issues when identified.

Since the 2018 Probabilistic Assessment, the reported forecast reserve margin for 2022 has increased, mainly due to reductions in the load forecast.

Risk Scenario Results

Modelling Hydro units using Lower Quartile Hydro Conditions result in higher loss of load values as compared to the base case. It is to be expected but this increase in the LOLH and EUE is not anticipated to cause any reliability issues. Since the difference in LOLH and EUE values between the Base Case and Sensitivity Case is quite low, its affects can be mitigated using emergency assistance if needed.

Sensitivity Case summary of Results

	2022	2024
EUE (MWh)	**319.2**	**59.7**
EUE (ppm)	**13.2**	**2.4**
LOLH (hours/year)	**3.5**	**0.6**

Chapter 4: MRO - SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP Assessment Area is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Key Assessment Takeaway

Southwest Power Pool demonstrated that many low probability events overlaid can impact their Reliability Indices. A significant increase in forced outage rates, coupled with a low wind output, on a hot summer day can create~~d~~ the conditions for increased risk to EUE and LOLH. This scenario ~~immensely stressed the conditions studied under the Base Case,~~ resulted with over 99% of the potential risk identified occurring during summer peak load hours~~,~~ and demonstrated a higher loss of load

Risk Scenario Description

SPP has seen an increase in installed wind and a slight increase in forced outage rates over the past few years. Therefore, SPP chose a low wind output scenario paired with an increase in conventional forced generation outages as the 2020 ProbA Regional Risk Scenario. The historical weather year chosen was ~~with~~ the lowest capacity factor output on summer peak hours between years 2012 to 2019 was used to model a low wind scenario. When determining the lowest performing wind year, only peak hours (Hour Ending 1~~2~~ PM to 8 PM) during months June, July, and August were analyzed to derive the average capacity factor by year. Through this analysis, 2012 wind year was modeled with each historical load year (2012 to 2019) in the risk scenario. The weighted forced outage rate of the Base Case study was approximately 12.5%. The weighted forced outage rate for all conventional resources were increased proportionally and applied to each resource to achieve an SPP weighted forced outage rate of 15%. The regional risk scenario was performed on year 2024 to reflect additional generation retirements and projected installed wind capacity.

Base Case Results

No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP Assessment Area. Reserve margins are well above 20% in both study years and no major impacts were observed related to resource retirements. In addition, the 2018 Probabilistic Assessment Base Case results for 2022 were the same for the 2020 Base Case results, ~~i.e.~~i.e., zero loss of load.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	27.6%	26.8%
Reference	15.8%	15.8%
~~ProbA Forecast Operable~~	~~13.6%~~	~~13.3%~~
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.00**	**0.00**
EUE (ppm)	**0.00**	**0.00**
LOLH (hours/year)	**0.00**	**0.00**

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	--	**72.6**

Commented [WP74]: There is a period after the word "hours" in the Key Assessment Takeaway box. Something is missing with the rest of the verbiage in read. I don't understand what it means.

Commented [AC75R74]: Edited wording

Commented [JS76]: What about TRE and SERC?

Commented [AC77R76]: SPP Planning coordinator footprint does not extend into SERC and TRE.

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Commented [WP78]: Hour ending or hour beginning?

Please consider using military time (hour ending or hour beginning 12:00 to 20:00).

Commented [JS79R78]: Military time may not be best for the end use reader. Moved to 12 hour clock with hour ending to address comment. Modified other sections of the document with times to maintain consistent explanation.

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Commented [JS80]: I believe that SPP's RM Reference level is 12%.

Commented [AC81R80]: The reference margin is converted from 12% to 15.8% SPP Coincident peak to meet requests by NERC and match LTRA submissions

Commented [JS82]: Please explain this parameter.

Commented [AC83R82]: Reduction of the anticipated PRM to account for conventional resources' weighted average forced outage rates in the SPP system that are used in the PRobA before the NERC ProbA is performed. It is a deterministic calculation

EUE (ppm)	--	**2.44**
LOLH (hours/year)	--	**0.113**

The results of the risk scenario showed an increase of potential loss of load, which reflects a slight increase in ~~the low probability of increased~~ summer forced outages paired with a low output wind year across the summer peak periods. Scenario analysis results show that LOLH and EUE values increase for 2024 when compared to the base case results. The modeling of the lowest wind output year paired with all load years showed the most impact in contributing approximately 80% to the increase of EUE and LOLH. Over 99% of the EUE and LOLH events occurred during the summer season. All risk was identified on peak load hours.

Chapter 5: NPCC

The Northeast Power Coordinating Council (NPCC) region has ~~divides their region into~~ five Assessment ~~different~~ A~~a~~reas.~~areas and provides a report out of each region.~~ ~~The~~Areas. The following pages contain the results for each Assessment Area~~sub-region of NPCC~~. For each of the Risk Scenario results sections, a link to a more detailed report covering the modeling assumptions and results can be found in Appendix E. Note that the metrics estimated are consistent with NPCC's Resource Adequacy – Design Criteria[16].

> **Key Assessment Takeaway**
>
> NPCC's ~~multiple different~~ A~~a~~ssessment A~~assessment a~~reas generally pursued removing Tier 1 resources as their ~~the same~~ risk scenario, with the ~~sole~~ exception of Ontario ~~as such a scenario did not differ much from their Base Case assumptions.~~'s choice to study nuclear refurbishment project delays. ~~NPCC~~The assessment demonstrated that with the removal of Tier 1 resources and transmission projects, the NPCC~~ir~~ Area Reliability Indices did not notably ~~rise~~ increase from the Base Case ~~significantly~~ for ~~each~~ all Assessment Areas~~.~~, including Ontario. In

NPCC - Maritimes

The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas. It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a ~~total~~ population of 1.9 million ~~people~~. There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. Demand for the Maritimes Area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas.

Risk Scenario Description

Tier 1 resources[17] were removed in other NPCC areas~~,~~. T~~t~~he low levels of Tier 1 resources in the Maritimes Area would not be an adequate test for severe conditions. For this reason, the Area assumed the winter wind capacity is de-rated by half (1224 MW to 612 MW) for every hour in December, ~~January~~January, and February to simulate widespread icing conditions and that only 50% (from 532 MW to 266 MW) of natural gas capacity is available due to winter curtailments of natural gas supplies. Dual fuel units are assumed to revert to oil.

The Area has a diverse resource mix, and this scenario tests the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios did not meet the degree of severity and likelihood. This scenario was chosen ~~now~~ to allow a direct comparison between the NERC and NPCC probabilistic analyses as the same severe scenario was used for both.

The results of this risk scenario are valuable to resource planners since they demonstrate a high level of reliability by meeting the NPCC loss of load expectancy (LOLE) target of not more than 0.1 days per year of exposure to load loss despite the severity of the scenario. Note that the required maximum LOLE for loss of load due to resource deficiencies is less than 0.1 days per year. ~~This would equate to a value of 2.4 hours for the loss of load hours (LOLH) measured in the ProbA analysis.~~ Hence, since the LOLH value for both the base case and risk scenarios are less than this value, the NPCC target is met for both study years.

Base Case Results

The base case reserve margin for 2022 was 21%, slightly higher than the Area's target of 20%. In the short term, unexpected delays in the development of Advanced Metering Infrastructure in New Brunswick which led to

[16] i.e., they are calculated following all possible allowable "load relief from available operating procedures". For more information see Directory #1 (npcc.org)

[17] The term "Tier" is used to describe categories of resources. This document is to be read alongside the NERC Long-Term Reliability Assessment that defines these categories.

Commented [JS84]: Arun Narang (Hydro One): "I'm finding the "Key Assessment Takeaway" difficult to understand…. Last sentence in particular seems garbled"

Commented [JS85R84]: Added clarity to the takeaway.

Commented [JS86]: From Aran Narang (Hydro One): "Appendix E does not contain the report. It merely provides a weblink to the report "

Commented [JS87R86]: Clarity added to address the comment.

Commented [JS88]: From Araun Narang (Hydro One): "What does "Tier 1" refer to … some explanation might be helpful…. "

Commented [JS89R88]: Added link to LTRA with definitions and rephrased sentence to add clarity.

Commented [WP90]: I don't think this is correct.

Commented [JS91R90]: Correct, removed the sentence.

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conservative short term increases in load forecasts, on peak sales of firm capacity to neighboring jurisdictions, and retirement of small thermal generators in PEI and NM has reduced the base case planning reserve margins to levels slightly below the target levels of 20% in 2024, respectively.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	2024
Anticipated	19.3%	20.9%
Reference	20.0%	20.0%
Annual Probabilistic Indices		
	2022	2024
EUE (MWh)	0.575	1.125
EUE (ppm)	0.021	0.039
LOLH (hours/year)	0.010	0.023

For the two studied years, this gave rise to non-zero values of EUE and LOLH with pronounced weighting during the months of December, January, and February, however the values are low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 0.575 MWh and 0.010 hours, respectively. The results are slightly worse for 2024 at 1.125 MWh and 0.023 hours, respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.021 and 0.039 for the years 2022 and 2024, respectively.

Risk Scenario Results

As expected, with the additional loss of half of the Area's wind and natural gas resources over and above the normal probability for loss of system resources, the risk scenarios reduce both the planning reserve margins to levels below the Area's target of 20%. Forecast ranges for planning reserves are 17% and 15% for the two study years of 2022 and 2024, respectively.

Scenario Case Summary of Results		
	2022	2024
EUE (MWh)	4.161	6.718
EUE (ppm)	0.149	0.236
LOLH (hours/year)	0.077	0.113

For the two studied years, this gave rise to non-zero values of EUE and LOLH again with pronounced weighting during the months of December, January, and February and again the values are still low being in the order of single digits or fractions of MWh and hours. The results for 2022 are 4.161 MWh and 0.077 hours respectively. The results are slightly worse for 2024 at 6.718 MWh and 0.128 hours respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.149 and 0.236 for the years 2022 and 2024.

NPCC - New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional bulk power system (BPS). The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Risk Scenario Description

Currently, in the probabilistic reliability analysis, the seasonal capacity ratings of the wind and solar resources are represented by a single value applicable to every hour of the day. The single value of the seasonal rating is based on the resource's seasonal claimed capability that are established using its historical median net real power output during the reliability hours (hours ending 14:00 through 18:00 for the summer period, and 18:00 through 19:00 for the winter period). As the system evolves with higher Behind-the-Meter solar penetration, the daily peaks may occur in the hours outside of the established reliability-hours window. The reduction in the wind and solar resources' rating is meant to identify the impact on system reliability if the current rating methodology overstates the capacity value of these resources in the future with the peaks occurring in different hours. The removal of the Tie 1 future resources

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is to take a conservative approach and identify the reliability consequences to the New England system if the in-service of these future resources is delayed.

Base Case Results

For year 2022, the 2018 study estimated an annual LOLH of 0.007 hours/year and a corresponding EUE of 2.713 MWh. In this year's study, the LOLH and the EUE slightly increased to 0.008 hours/year, and 3.292 MWh, respectively.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**29.4**	**18.95**
Reference	**13.9**	**12.7**
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**3.292**	**58.62**
EUE (ppm)	**0.027**	**0.471**
LOLH (hours/year)	**0.007**	**0.095**

For year 2024, results show that the LOLH and the EUE values will increase to 0.095 hours/year, and a corresponding EUE of 58.618 MWh. The increase in LOLH and EUE is mainly attributed to the expected retirement of ~~Mystics~~~~Mystic~~Mystic Units 8 and 9 (~1,400 MW) in the Boston area.

Risk Scenario Results

As expected, assuming less capacity contribution from the wind and solar resources and the delay of Tier 1 new resources will increase the LOLH and the EUE of the system. The LOLH and the EUE values are estimated to increase to 0.011 hours/year, and 5.3 MWh for 2022, respectively and to 0.135 hours/year, and 88.1 MWh for 2024, respectively. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.038 and 0.625 for the years 2022 and 2024.

Scenario Case Summary of Results		
	2022	**2024**
EUE (MWh)	**5.3**	**88.1**
EUE (ppm)	**0.038**	**0.625**
LOLH (hours/year)	**0.011**	**0.135**

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NPCC - New York

The ~~NYISO~~New York ISO (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. This represents approximately 37,317 MW[18] of ~~Existing~~-Certain resources and Net Firm transfers anticipated for 2021. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Commented [JS92]: From Arun Narang (Hydro One): "How much capacity (MW)?"

Commented [AK93R92]: NERC LTRA referenced and footnoted.

Risk Scenario Description

This scenario evaluates the reliability of the system under the assumption that no major Tier 1 generation (see Table 5.1~~) or~~) or transmission (see Table 5.2) projects come to fruition within the ProbA study period. Below is a list of the major Tier 1 proposed transmission and generation projects that were removed from the Base Case.

Table 5.1: Tier 1 Generation Projects for NPCC – New York			
Unit Name	**Name Plate [MW]**	**Zone**	**2020 RNA COD**
Ball Hill Wind	100	A	12/2022
Baron Winds	238.4	C	12/2021
Cassadaga Wind	126.5	A	12/2021
Eight Point Wind Energy Center	101.8	B	12/2021

[18] NERC_LTRA_2020.pdf

Calverton Solar Energy Center	22.9	K	12/2021
Roaring Brook Wind	79.7	E	12/2021

Table 5.2: Tier 1 Transmission Projects for NPCC – New York

Queue #	Project Name	Zone	CRIS Request	SP MW	Interconnection Status	2020 RNA COD (In-Service Date)
Proposed Transmission Additions, other than Local Transmission Owner Plans (LTPs)						
Q545A	Empire State Line	Regulated Transmission Solutions	N/A	N/A	Completed TIP Facility Study (Western NY PPTPP)	5/2022
556	Segment A Double Circuit				TIP Facility Study in progress (AC PPTPP)	12/2023
543	Segment B Knickerbocker-Pleasant Valley 345 kV				TIP Facility Study in progress (AC PPTPP)	12/2023
SDU	Leeds-Hurley SDU	System Deliverability Upgrades (SDU)	n/a	n/a	SDU triggered for construction in CY11	Summer 2021
CRIS Request						
430	Cedar Rapids Transmission Upgrade	D	80	80	CY17	10/2021

This scenario provides an indication of the potential reliability risks related to projects relied upon in the NYISO's 2020–2021 Reliability Planning Process not materializing.

Base Case Results

The MARS planning model was developed by NPCC with input from each Area (Ontario, New York, New England, ~~Hydro~~ Quebec, and Maritimes). The New York Loss of Load Hours (LOLH) for 2022 and 2024 are 0.003 and 0.029 (hours/year), respectively, with corresponding Expect Unserved Energy (EUE) values of 0.594 and 6.837 (MWh), respectively.~~).~~ These values trend higher than the past ProbA results. The trend is mainly due to the decrease in the forecasted Prospective Reserve Margin and Operable Reserve Margins.[19] The New York area is summer-peaking and the LOLH and EUE risk occurs primarily during the summer months.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.8%	18.6%
Reference	15.0%	15.0%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.594**	**6.837**
EUE (ppm)	**0.004**	**0.046**
LOLH (hours/year)	**0.003**	**0.029**

Risk Scenario Results

Scenario Case Summary of Results		
	2022	**2024**

[19] As defined by NERC for the Long-Term Reliability Assessments (LTRA) and Probabilistic Assessment (Prob A) application.

EUE (MWh)	**0.681**	**13.904**
EUE (ppm)	**0.005**	**0.093**
LOLH (hours/year)	**0.003**	**0.045**

As expected, if no major Tier 1 transmission and generation projects are assumed to come in-service within ProbA Study Period, the LOLH and EUE results are observed to be higher than ProbA Base Case. The LOLH for 2022 and 2024 are 0.003 and 0.045 (hours/year), respectively, with corresponding EUE values of 0.681 and 13.904 (MWh). Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.005 and 0.093 for the years 2022 and 2024.

NPCC - Ontario

The Ontario Independent Electricity System Operator (IESO) is the Planning Coordinator, Resource Planner and Balancing Authority for Ontario, as defined by the North American Electric Reliability Corporation. As detailed in Section 8 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO follows the Northeast Power Coordinating Council resource adequacy criterion. ORTAC Section 8.2 states that the IESO will not consider emergency operating procedures for long-term capacity planning. The IESO also currently does not consider assistance over interconnections with neighboring Planning Coordinator Areas as contributing to resource adequacy needs in the Annual Planning Outlook resource adequacy assessments.

Risk Scenario Description

Ontario currently has 18 nuclear units, six of which are expected to retire by 2024/2025. As of today, one unit has been refurbished with nine more units being refurbished over the next decade. Given the size of each nuclear unit, there is a significant risk to resource adequacy if the return of ~~units~~ any unit is delayed due to unforeseen circumstances.~~,~~ For th~~is~~e reason, ~~for~~ the IESO ~~to pick~~chose refurbishment project delays for their risk scenario. Additionally, ~~T~~the demand forecast was increased by 5% for Ontario risk scenario to reflect possible rapid economic recovery from COVID-19 impacts.

Commented [JS94]: From Arun Naragn (Hydro One): “Odd sentence structure”

Commented [JS95R94]: Suggested edits here for clarity.

Removing Tier 1 resources would not have been an appropriate scenario to test the system because those resources amounted to only 360 MW.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	20.1%	11.3%
Reference	23.8%	16.8%
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	**0.000**	**0.049**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

~~Base Case Summary of Results~~		
~~Reserve Margin (RM) %~~		
	~~2022~~	~~2024~~
~~Anticipated~~	~~20.1%~~	~~11.3%~~
~~Reference~~	~~23.8%~~	~~16.8%~~
~~Annual Probabilistic Indices~~		
	~~2022~~	~~2024~~
~~EUE (MWh)~~	~~0.000~~	~~0.049~~
~~EUE (ppm)~~	~~0.000~~	~~0.000~~
~~LOLH (hours/year)~~	~~0.000~~	~~0.000~~

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Base Case Results

The previous ProbA estimated an annual LOLH of 0.0 hours/year and EUE of 0.0 MWh for the year 2022. The median peak demand forecast for 2022 has increased by 2.5% compared to the 2018 forecast. The current forecasts are LOLH of 0.0 hours/year and EUE of 0.049 MWh for the year 2022. No difference in the estimated LOLH and a marginal difference in EUE are observed between the two assessments.

Risk Scenario Results

The ProbA Risk Scenario estimated an annual LOLH of 0.0013 hours/year and EUE of 0.0925 MWh for the year 2022. For the year 2024, the estimated annual LOLH was 0.~~1408~~ 171 hours/year and EUE was ~~79.958~~599.7 MWh, as expected. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are 0.000 and 0.692 for the years 2022 and 2024.

Scenario Case Summary of Results		
	2022	2024
EUE (MWh)	0.0925	99.7
EUE (ppm)	0.000	0.692
LOLH (hours/year)	0.0013	0.171

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The results emphasize the resource adequacy needs that Ontario faces in the mid to long-term. The IESO is transitioning to the use of competitive mechanisms with stakeholder inputs to meet Ontario's adequacy needs.

NPCC - Québec

The Québec Aassessment ~~Aassessment a~~rea (Province of Québec) is a winter-peaking NPCC aArea~~subregion~~ that covers 595,391 square miles with a population of 8.5~~eight and a half~~ million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Risk Scenario Description

In this scenario, it is assumed that Tier 1 resources be removed to test the reliability impacts associated with the most likely and therefore realistic shortages. Other scenarios are less likely compared to this scenario.

Base Case Results

The base case reserve margin for 2022 was 13.2%, which is higher than the Area's reference reserve margin of 10%.

In the short term, increase in load forecasts, on peak sales of firm capacity to neighboring jurisdictions reduced the base case planning reserve margins to levels slightly below the reference reserve margin of 10% in 2024.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	2024
Anticipated	13.5%	14.0%
Reference	10.1%	10.1%
Annual Probabilistic Indices		
	2022	2024
EUE (MWh)	0.00	0.000
EUE (ppm)	0.00	0.000
LOLH (hours/year)	0.00	0.000

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For the two studied years, the results are zero for EUE and LOLH. Expressed in terms of Parts per Million MWh of Net energy for load, the EUE values are zero for the years 2022 and 2024.

Risk Scenario Results

As expected, after removing all Tier-1 resources, the risk scenarios reduce both the planning reserve margins to levels

below the Area's target of 10%. Forecast ranges for planning reserves are 13.0% and 8.9% for the two study years of 2022 and 2024~~.~~, respectively.~~.~~ For the two studied years, the EUE and LOLH remain close to zero.

Scenario Case Summary of Results		
	2022	2024
EUE (MWh)	0.00	0.000
EUE (ppm)	0.00	0.000
LOLH (hours/year)	0.00	0.000

Chapter 6: RF - PJM

PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. It is part of the Eastern Interconnection and serves approximately 65 million people over 369,000 square miles.

Key Assessment Takeaway

PJM decided to remove all Tier 1 resources as part of their scenario. They demonstrate no significant rise in Reliability Indices based on these removals.

Risk Scenario Description

The risk scenario considers the removal of all Tier 1[~~20~~] units[21] from the simulation. This scenario serves as a proxy for potential withdrawals or delays of queue projects in the PJM Interconnection Queue. PJM chose this scenario due to the delay in the Reliability Pricing Model's (RPM) schedule (resulting from the Minimum Offer Price Rules proceedings at FERC); RPM provides entry price signals for planned resources such as those labeled as Tier 1 resources. Furthermore, the risk scenario ~~it~~ provides resource adequacy planners with ~~with~~ an opportunity to analyze the impact of a higher RTO-wide forced outage rate on reliability metrics due to the fact that, in general, Tier 1 units are expected to have lower forced outage rates than existing units. This is because most Tier 1 units are combined cycle units. This scenario provides value to resource adequacy planners due to the fact that it considers reserve margins that are much lower than current reserve margins at PJM.

Base Case Results

The Base Case results in LOLH and EUE equal to zero for both 2022 and 2024 due to large Forecast Planning Reserve Margins (36.6% and 40.1%, respectively). These reserve margins are significantly above the reference values of 14.5% and 14.4%, respectively. Note that these large Forecast Planning Reserve Margin values include Tier 1 resources (~15,000 MW in 2022 and ~23,000 MW in 2024). Historically, a significant share of Tier 1 resources, 20%-30%, drop out of the Interconnection Queue process.~~%.~~

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**33.5%**	**36.6%**	**40.1%**
Reference	**15.8%**	**14.5%**	**14.4%**
~~ProbA Forecast Operable~~	~~22.5%~~	~~25.6%~~	~~29.0%~~
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.000**	**0.000**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**
2022*: results from the 2018 ProbA			

The LOLH and EUE in the 2020 study are identical to the values reported in the 2018 study. There are no differences in the EUE and LOLH results because in both studies the Forecast Planning Reserve Margin values are well above the reference values. Furthermore, the Forecast Planning Reserve Margin for 2022 in the 2020 study has actually increased compared to the value in the 2018 study due to a slightly higher amount (~300 MW) of Forecast Capacity Resources and a lower (~3,000 MW) Net Internal Demand value.

Risk Scenario Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	**25.9%**	**24.1%**
Reference	**14.5%**	**14.4%**
~~ProbA Forecast Operable~~	~~15.3%~~	~~13.6%~~

~~[20] "Tier 1" resources refers to planned resources in the PJM Interconnection Queue with an executed Interconnection Service Agreement (or its equivalent). See footnote ## for more reference to the term "Tier"~~

[21] "Tier 1" resources refers to planned resources in the PJM Interconnection Queue with an executed Interconnection Service Agreement (or its equivalent). See footnote 15 for more reference to the term "Tier"

Commented [JU96]: This mentions Tier 1, where is that defined? Someone reading this will need to know.

Commented [JS97R96]: Footnote added to add clarity. Referenced previous mention of "Tier" footnote for link.

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Commented [JG98]: For PJM, I would like a little more explanation for the content in the 'Risk Scenario Description' within the report – similar to the detail for NPCC. Just a sentence or two justifying the selection of Tier 1 resources when compared to various fuel type outages within their footprint. For example, PJM did not evaluate a specific stress scenario of losing certain fuel types, because that the amount of MWs associated with these resources was less than the Tier 1 resources.

In short, just list what options were considered and why they were not selected (most likely because selecting Tier 1 resources was a more conservative approach).

Commented [JS99R98]: PJM has added clarification on their scenario description.

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Commented [JU100]: This is due to a huge generation queue. Can they add something around the probability of the huge queue and likelihood of all of it actually getting installed? Is it 50% or less or more than 50%? What does that do to these numbers?

Commented [JS101R100]: Clarity added. Additionally, PJM has added the share of Tier 1 resources that ultimately drop out of the Interconnection Queue. PJM reemphasized that by looking at the Base Case results and the Risk Scenario result, the removal of 20%-30% of Tier 1 resources will also produce LOLH and EUE equal to zero.

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Risk Scenario Results

The regional risk scenario yields LOLH and EUE values that are practically zero for both 2022 and 2024 (the EUE value of 0.33 MWh in 2024 is, for all intents and purposes, a negligible value).

Annual Probabilistic Indices

	2022	2024
EUE (MWh)	**0.000**	**0.330**
EUE (ppm)	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**

These results are also caused by Forecast Planning Reserve Margins, even after excluding Tier 1 resources, which are well above the reference values (i.e., 25.9% vs a reference value of 14.5% in 2022 and 24.1% vs a reference value of 14.4% in 2024).

Note that PJM's anticipated reserve margins in the Base Case and the Risk Scenario are largely driven by past and expected outcomes of PJM's capacity market, the Reliability Pricing Model, which by design allows for the possibility of procuring reserve margin levels above the reference levels[22].

[22] Sections 3.1 – 3.4 in PJM Manual 18 available at https://www.pjm.com/~/media/documents/manuals/m18.ashx

Chapter 7: SERC

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. The regional entity includes four NERC assessment areas: SERC-East, SERC-Central, SERC-Southeast, and SERC-Florida Peninsula.

In addition to seeing loss of load risk during peak load summer months, SERC is also experiencing tighter operating conditions during non-summer months. One factor that has contributed to this trend is the amount of thermal generation resources taking planned maintenance outages during the shoulder months. While the LTRA projects reserves for summer, winter, and annual assessments, it may not highlight risk, if any, during spring and fall.

> **Key Assessment Takeaway**
>
> SERC's increase of maintenance outages on their Base Case did not demonstrate a significant increase of Reliability Indices. In response, SERC then altered their cases to ensure each of the regions started at a LOLE of 0.1. This change allowed SERC to determine their Reliability Indices produce an exponential relationship to the increase of maximum capacity undergoing maintenance. This is able to be mitigated by proper coordination of planned outages.

SERC has not experienced any reliability events directly related to planned maintenance outages. However, reports on events in neighboring regions highlight the importance of evaluating this risk for SERC. A FERC and NERC staff report on the 2018 cold weather event[23] identified that planned outages contributed to system reliability risk in the South-Central United States. Additionally, MISO declared Maximum Generation Events in January and May of 2019 which supports MISO's finding that the combination of high planned outages, reduced capacity availability, and volatile load has increased the risk of capacity shortages during non-summer months.[24]

Risk Scenario Description

To investigate the impact of planned maintenance outages on system risk, SERC conducted a sensitivity study in the 2020 Probabilistic Assessment that increased the amount of planned maintenance outages on the SERC system for year 2024. This sensitivity study helps resource adequacy planners understand how planned maintenance outages can impact the distribution of loss of load risk across all times of the year and it improves the ability to plan maintenance outage schedules that minimize loss of load risk.

SERC incrementally increased the planned maintenance rates for thermal resources to test the reliability of the SERC system under a scenario with higher levels of planned maintenance outages. Given that the base case metrics are very small for many of SERC's sub-regional areas, known as metric reporting areas (MRAs), we performed a two-part sensitivity study. One, starting with the base report and the other starting at each MRA's PRM resource level, where the starting point reserves were adjusted for each MRA to reach the LOLE target of 0.1 days/year. In both instances, the base case planned outage rates were multiplied by factors of 1.5, 2 and 2.5.

Base Case Results

The 2020 Probabilistic Assessment Base Case results show that each of the MRAs are projected to have reserves and access to imports from neighboring areas that are well more than that needed to meet the 0.1 days/year LOLE target. In the 2020 study year, the planning reserve margins (PRM) results are 21.8% for 2022 and 18.9% for 2024. These projections are higher than the SERC 2018 Probabilistic Assessment study. The increase in PRM could be attributed to several modeling changes in the 2020 study, particularly the integration of Florida Peninsula, a rapidly changing capacity mix, and updates to transfer capacities. The snippets of the 2020 LTRA tables for the base case results for all SERC MRAs are found below.

[23] FERC and NERC Release Report on January 2018 Extreme Cold Weather Event

[24] Resource Availability and Need, Evaluation Whitepaper September 2018 and MISO January 2019 Max Gen Event Overview and May 2019 Max Gen Event Overview

SERC-Central: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**24.9%**	**26.4%**	**27.0%**
Reference	**14.4%**	**15.0%**	**15.0%**
~~ProbA Forecast Operable~~	~~**17.7%**~~	~~**17.9%**~~	~~**18.4%**~~
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.001**	**0.001**
EUE (ppm)	**0.000**	**0.000**	**0.000**
LOLH (hours/year)	**0.000**	**0.000**	**0.000**

SERC-East: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**24.9%**	**22.8%**	**23.9%**
Reference	**14.4%**	**15.0%**	**15.0%**
~~ProbA Forecast Operable~~	~~**18.0%**~~	~~**14.9%**~~	~~**15.9%**~~
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.000**	**0.717**	**5.262**
EUE (ppm)	**0.000**	**0.003**	**0.024**
LOLH (hours/year)	**0.000**	**0.001**	**0.009**

SERC- Southeast: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**32.4%**	**35.8%**	**39.1%**
Reference	**14.4%**	**15.0%**	**15.0%**
~~ProbA Forecast Operabl~~	~~**24.7%**~~	~~**26.9%**~~	~~**30.2%**~~
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**0.00**	**0.009**	**0.028**
EUE (ppm)	**0.00**	**0.000**	**0.000**
LOLH (hours/year)	**0.00**	**0.000**	**0.000**

SERC-Florida Peninsula: Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	**N/A**	**21.6%**	**22.8%**
Reference	**N/A**	**15.0%**	**15.0%**
~~ProbA Forecast Operable~~	~~**N/A**~~	~~**10.2%**~~	~~**11.4%**~~
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	**N/A**	**22.66**	**2.262**
EUE (ppm)	**N/A**	**0.096**	**0.009**
LOLH (hours/year)	**N/A**	**0.035**	**0.004**

An asterisk (~~2022~~*) denotes~~:~~ results from the 2018 ProbA

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Risk Scenario Results

When using the maintenance multiplier of 1x, maintenance outages are primarily scheduled in March-May and September-November for SERC-C, SERC-SE, and SERC-E. In SERC-FP, maintenance outages are scheduled throughout the year, except for summer. Increasing the multiplier beyond 1.5x causes maintenance outages to begin to be scheduled in the peak load summer months. Figure 7.1 shows how the multipliers impact the maximum capacity undergoing maintenance during the simulation.

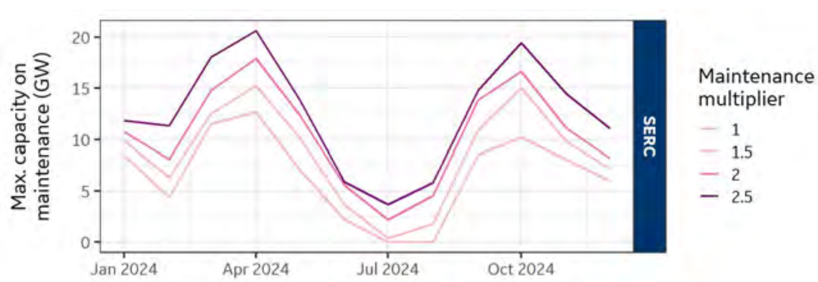

Figure 7.1 Maximum simultaneous capacity on maintenance outage for all of SERC

The reliability metrics for the base case are summarized in Table 7.1. The MRAs that had a measurable amount of LOLE in the base case (SERC-E and SERC-FP) see an increase in their observed metrics as the maintenance multiplier is increased. However, this increase in LOLE is somewhat moderate. For instance, in the case with double the maintenance rates, both SERC-E and SERC-FP have a LOLE below 0.1 days/year.

Table 7.1: Reliability Indices for Increased Maintenance for Base Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
SERC-C	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.002	1.1	0.005
	2.5	0.008	0.017	12.2	0.055
SERC-SE	1	0.000	0.000	0.0	0.000
	1.5	0.000	0.000	0.0	0.000
	2	0.001	0.001	0.4	0.002
	2.5	0.008	0.013	7.5	0.030
SERC-E	1	0.004	0.009	5.3	0.024
	1.5	0.012	0.019	12.3	0.056
	2	0.085	0.136	107.8	0.490
	2.5	0.277	0.574	517.4	2.349
SERC-FP	1	0.003	0.004	2.3	0.009
	1.5	0.018	0.024	19.1	0.079
	2	0.099	0.147	141.4	0.583
	2.5	0.320	0.518	513.3	2.114
SERC	1	0.006	0.013	7.6	0.006
	1.5	0.029	0.043	31.5	0.023
	2	0.183	0.284	250.8	0.186
	2.5	0.588	1.087	1,050.4	0.778

Given that the base case metrics are very small for many of the MRAs, SERC performed a second set of simulations to better understand the impact of higher maintenance outages in all MRAs. Instead of starting with the base case scenario, the starting point was the final step in the Probabilistic Assessment's interconnected PRM simulation, where every MRA in the model experiences a LOLE of 0.1 days/year. This provides a starting point with observable loss of load statistics for all the areas. Table 7.2 show that as the maintenance multiplier increases in the PRM case, all the MRAs experience an exponential increase of LOLE and other metrics. The increase is similar across all MRAs with the exception that SERC-FP experiences a larger-than-average increase in LOLE. Figure 7.2 also highlights this same exponential increases under this second simulation.

Table 7.2: Reliability Indices for Increased Maintenance for Planning Reserve Margin Case, Year 2024

MRA	Maintenance Multiplier	LOLE (days/yr)	LOLH (hrs/yr)	EUE (MWh/yr)	EUE (MPM)
SERC-C	1	0.100	0.263	255.8	1.166
	1.5	0.156	0.379	402.4	1.835
	2	0.594	1.517	2,139.7	9.757

	2.5	1.772	4.863	6,560.1	29.916
SERC-SE	1	0.099	0.233	280.9	1.113
	1.5	0.136	0.296	349.6	1.386
	2	0.521	1.131	1,418.4	5.623
	2.5	1.800	4.442	6,079.4	24,098
SERC-E	1	0.100	0.256	275.5	1.251
	1.5	0.142	0.331	343.8	1.561
	2	0.554	1.204	1,208.4	5.486
	2.5	1.799	4.634	5,218.9	23.691
SERC-FP	1	0.100	0.203	160.0	0.659
	1.5	0.261	0.440	394.7	1.626
	2	0.805	1.474	1,573.9	6.482
	2.5	2.321	4.810	5,484.6	22.588
SERC	1	0.307	0.767	1,527.0	1.131
	1.5	0.561	1.197	2,177.4	1.613
	2	1.908	4.485	8,815.7	6.532
	2.5	6.523	18.373	35,211.9	26.091

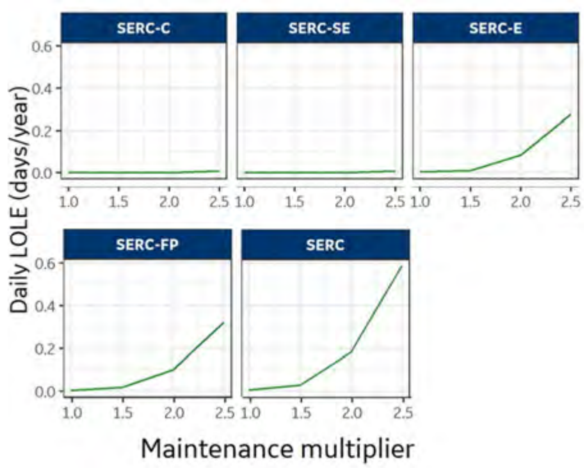

Figure 7.2 Loss of Load Statistics by Maintenance Multiplier per MRA

Figure 7.3 shows that under the 1x multiplier case, the majority of MRAs have the largest accumulation of LOLE in the summer. SERC-FP is the exception, with nearly 20% of the LOLE occurring during the winter. As the maintenance multiplier increases, most MRAs experience less LOLE in the summer and more LOLE in the spring and fall. SERC-FP is again the exception, with the majority of the LOLE moving to the winter and a smaller portion of LOLE moving to the fall.

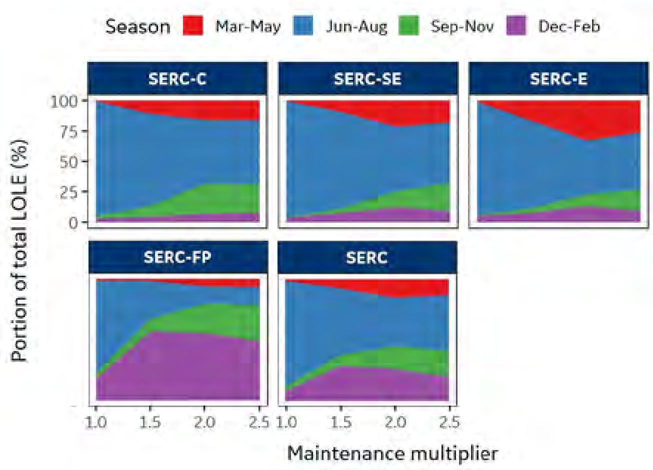

Figure 7.3 Seasonal LOLE Distribution for PRM Cases with Increased Maintenance

Risk and Recommendations

The sensitivity scenarios indicate that the risk in year 2024 associated with increased planned maintenance outages is low to moderate. For instance, the MRAs with the highest increase in LOLE, SERC-E and SERC-FP were still below 0.1 LOLE with double the maintenance rates. The small increase in LOLE for the SERC MRAs resulting from increased planned maintenance outages can be partially attributable to the fact that the SERC MRAs in 2024 are projected to have reserves and access to imports from neighboring areas that is well in excess of that needed to meet the 0.1 days/year LOLE target.

The results of this sensitivity study highlight the need for planned outage coordinators to develop unique maintenance schedules that align with expected local weather and system conditions. For this reason, the optimal time periods for scheduling maintenance outages vary across the SERC MRAs.

It is worth noting that the model assumes an optimized outage schedule based on foresight of average weather conditions. The GE MARS software schedules planned outages with a "packing" algorithm that schedules maintenance in the weeks with highest margins. A further comparison between the maintenance schedule developed by GE MARS and historical maintenance schedules could be insightful in understanding the findings of this sensitivity study. A ~~link to the~~ redacted copy of the SERC 2020 Probabilistic Assessment report can be found in the SERC website by using the link in Appendix E.

Chapter 8: Texas RE – ERCOT

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas.

Key Assessment Takeaway

ERCOT demonstrates that by resampling their wind profiles with their load profile to emphasize low to moderate amounts of wind has a significant effect on their net load peaks, and as a result increase their Reliability Indices. This increase is similar to those that alter their system such that a LOLE of 1 day in 10 years is expected. This indicates that the ERCOT system increases in Reliability Indices for their scenario, while significant in comparisons to the Base Case, are not significant in comparison to industry accepted standards.

Risk Scenario Description

The total installed wind capacity in ERCOT is around 25 GW, and additional 13 GW of new wind is expected to come online in the next three to four years. Furthermore, the two Energy Emergency Alert (EEA~~-~~) events in 2019 summer were primarily due to low output from wind resources. In addition, simulated loss of load events in ERCOT are largely driven by high load, low wind output conditions. These conditions occur with relative rarity such that a relatively small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the base case simulations. Other aspects of the study can be found in Appendix B.

To construct the alternate wind profiles which reflect a higher likelihood of low wind output, a filter was performed for days in the simulated base case which had any firm loss of load. An alternate wind profile for each day was randomly selected from the wind profiles from this set of days. This re-shuffling of load and wind profiles was performed 100 times. The sampled sets of profiles which represent the most extreme and 10th most extreme sets of net load profiles were selected to be simulated for 2024. The criteria for most extreme was based on the set with the highest average net loads in the top 40 net load days.

Base Case Results

The Base Case study results in minimal reliability ~~events.~~ ~~As~~events. As compared to the 2018 ProbA Study, the reserve margin has increased substantially primarily due to increase in solar resources. More than 12GW of additional solar installed capacity is expected in 2022 now than was forecast when the 2018 ProbA Study was published. Compared to the results from the 2018 ProbA Study, LOLH decreased from 0.87 to 0.00 for the first study year. The results are driven by an increase in the Anticipated Reserve Margin, resulting from growth in planned solar and wind capacity.

Base Case Summary of Results		
Reserve Margin (RM) %		
	2022	**2024**
Anticipated	19.1%	15.5%
Reference	13.8%	13.8%
~~ProbA Forecast Operable~~	~~13.7%~~	~~10.3%~~
Annual Probabilistic Indices		
	2022	**2024**
EUE (MWh)	.05	12.86
EUE (ppm)	0.00	0.03
LOLH (hours/year)	0.00	0.01

Risk Scenario Results

Resampling the wind profiles on peak load days increased the average net load peak for the top 40 net load days by 235 MW for the 10th most extreme scenario and 525 MW for the most extreme scenario. A snapshot of the top 40 daily net load peaks for each of the scenarios is shown below in Figure 8.1. In the most extreme days in the risk scenarios, the daily net load peak is over 1,000 MW higher than in the base case.

Commented [JS102]: From Arun Narang (Hydro One): "A lot of emphasis on renewable generation (wind/solar) in the writeup…. Not much of a mention about conventional gen resources

Following up on above comment: there's some mention in Appendix B for all study regions
"

Commented [JS103R102]: As indicated in the comment, the Appendix B has a comparison of treatment of the resources in the study. This chapter focuses on the scenario chosen to study. As that scenario is not focused on conventional generation resources, there will not much language about them here. Rather, Appendix B has that language.

Commented [JS104]: From Arun Narang (Hydro One): "It would be interesting to review these study assumptions in light of recent events in Texas; Does this assessment adequately capture known risks?
"

Commented [JS105R104]: The risk scenario is not intended to address severe winter storm events and associated common-mode failures at thermal power plants, so that is why there is no mention of that in the write-up. Winter Storm Uri was unprecedented in terms of a combination of geographical extent, severity and duration. Going forward, ERCOT will focus on enhancing risk assessment associated with extreme winter events, including what is done for NERC's Probabilistic Assessments.

Commented [WP106]: Please spell out EEA

Commented [JS107R106]: Change made as requested.

Commented [JS108]: From Arun Narang (Hydro One): "No hint of concern for severe winter conditions, as experienced recently.
"

Commented [JS109R108]: The risk scenario is not intended to address severe winter storm events and associated common-mode failures at thermal power plants, so that is why there is no mention of that in the write-up. Winter Storm Uri was unprecedented in terms of a combination of geographical extent, severity and duration. Going forward, ERCOT will focus on enhancing risk assessment associated with extreme winter events, including what is done for NERC's Probabilistic Assessments.

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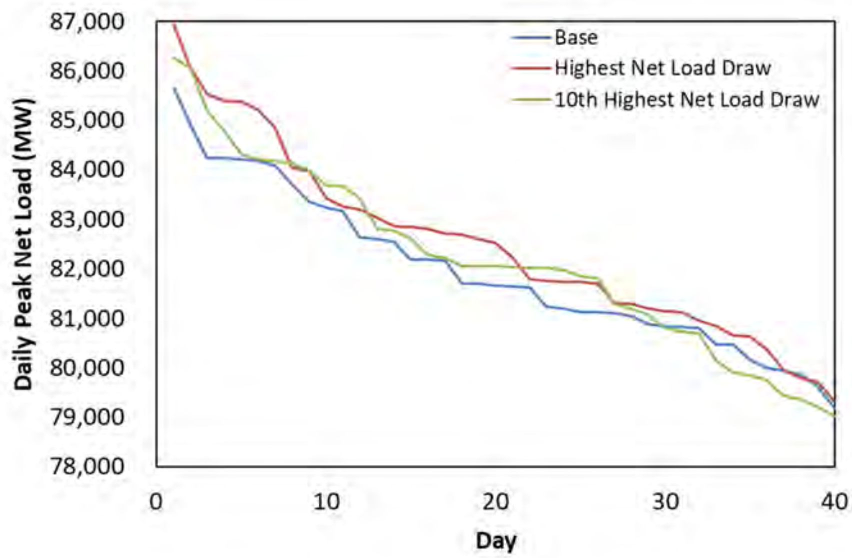


Figure 8.1 ERCOT's Load profiles for Various Assumptions

The increase in net load corresponds to a degradation of reliability when the risk scenarios are simulated. While the assumption that daily wind profiles from peak load days are fungible is not realistic, it likely provides an upper bound for the impact of wind profile uncertainty on average reliability metrics. The scenario results are compared to those found in the Base Case in Table 8.1 and highlight this upper boundary.

Table 8.1: Scenario Case Reliability Index Comparison

Reliability Index	Base Case	10th Highest Net Load Draw	Highest Net Load Dratw~~DrawtDrat~~
EUE [MWh]	12.86	31.0	64.72
LOLH [hrs/yr]	0.01	0.03	0.05

Since reliability metrics in the base case are quite low, the risk scenario impact appears quite large. EUE and LOLH in the highest net load draw scenario increase by a factor of approximately 5. However, simulating the risk scenarios at a lower reserve margin which is more consistent with industry standard reliability expectations (0.1 LOLE) suggests a smaller impact. In this case LOLH increases from .24 to .49 for the highest net load draw scenario.

Chapter 9: WECC

The Western Interconnection serves ~~a population of~~ over 80 million people. The interconnection spans 1.8 million square miles in all or part of 14 states, the Canadian provinces of British Columbia and Alberta, and the northern part of Baja California in Mexico. Due to the unique geography, demography, and history, the Western Interconnection is distinct in many ways from the other North American interconnections.

Key Assessment Takeaway

WECC, like NPCC, performs a simulation for multiple different Assessment Areas. These areas all were subject to a reduction of coal-fired generation and demonstrated varying results. In some areas, this scenario greatly impacted their Reliability Indices and in others, no significant increase was observed from the Base Case results. WECC determined that the impact of a reduction of coal-fired generation on the Reliability Indices depends heavily on the current penetration of coal-fired generation in the Assessment Area, as well as the Assessment Area's ability to take on external assistance under higher demand. Such a result is not indicative for more or less coal, but that the impact of faster retirements than expected has a varying impact on the Reliability Indices in each Assessment Area.

Risk Scenario Description

The Western Electricity Coordinating Council (WECC) Regional Risk Scenario examines the impacts to resource adequacy associated with potential coal-fired generation retirements. The generation resources included in this scenario started with the LTRA resources and removed additional coal-fired generation resources that are expected to retire but do not yet have an approved decommission plan.

Coal-fired generation is a key baseload component of the Western Interconnection's resource mix but is also one of the most controversial. With the retirement or planned retirement of considerable amounts of coal-fired generation, and an increase in variable energy resources, the need to ensure sufficient capacity to reliably meet electricity demand at any given hour within the Western Interconnection is becoming more significant. This scenario specifically analyzes the reliability impacts of retiring coal plants beyond those that are being retired in the LTRA; this assessment includes coal retirements based on the best information provided by stakeholders or are mandated by state polices. This scenario also provides insights into where additional risk may occur with fewer baseload resources and examines the effects of these potential retirements to help mitigate reliability risks to the Bulk Power System (BPS).

WECC's Reliability Risk Priorities focus on four reliability concerns: Resource Adequacy and Performance, Changing Resource Mix, Distribution System and Customer Load Impacts on the BPS, and Extreme Natural Events. It would be appropriate to study any of these topics, but Resource Adequacy incorporates elements of each priority and serves as the basis for additional studies in each of these priorities. If more information is desired, please see Appendix E for the link to WECC's Western Assessment that contains more details.

Coal-fired generation has historically been a major energy resource in the Western Interconnection. However, as the generation resource mix in the Western Interconnection transitions from thermal based resources to variable generation resources, coal-fired generation will continue to be retired. This study examines the impacts to resource adequacy and planning reserve margins associated with aggressive coal-fired generation retirements.

It is anticipated that coal-fired generation retirements will continue, both in response to governmental directives and for economic reasons. For the most part these baseload resources are being replaced by high variable generation such as wind and solar. Resource adequacy planners need to understand the variability associated with wind and solar generation and incorporate probabilistic studies in the resource adequacy planning process. This assessment is focused on examining the risks to resource adequacy associated with not having enough resources to meet demand following aggressive coal-fired generation retirements.

The chart (below in Figure 9.1) shows the amount of possible coal retirements over the next ten years that were not reported in the LTRA or Prob-A base case. The years 2022 and 2024 are highlighted as the years reported in the scenario. Accumulated coal-fired capacity retirements that were included in the ProbA scenario total over 2,300 MW.

Figure 9.1: WECC's Possible Coal Retirement Capacity by Year[25]

WECC - California – Mexico (CAMX)

The CAMX subregion is a summer peaking subregion that consists of most of the state of California and a portion of Baja California, Mexico. The CAMX subregion has two distinct peak periods, one in southern California and one in northern California, which benefits the subregion as there are resources available in one area when the other is experiencing their demand peak.

Demand

The CAMX subregion is expected to peak in late August at approximately 53,400 MW for both 2022 and 2024. Overall, the CAMX subregion should expect an 100% ramp, or 26,700 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 66,000 MW, which equates to a 24% load forecast uncertainty and could peak as high as 65,000 MW in 2024.

Commented [JS110]: From Aran Narang (Hydro One): "It seems that all of the assessments for WECC regions identify this ramp requirement from lowest to highest demand hour. None of the write-ups for the remaining regions (ERCOT, NPCC etc) make reference to this. "

Commented [JS111R110]: This is focused in these sections due to previous focus on the phenomenon from WECC stakeholders in this area.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 50,400 MW. Under low resource availability conditions, the CAMX subregion may only have 44,300 MW ~~available~~ to meet a 53,400 MW expected peak. The expected availability of resources on the peak hour in 2024 is 54,400 MW. Under low resource availability conditions, the CAMX subregion may only have 46,400 MW ~~available~~ to meet a 53,400 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 45,000 MW ~~of availability~~, the low availability end of the spectrum would only see a loss of 4,000 MW, or less than 10%. Whereas,

[25] For further information regarding this study please use the link in Appendix E to access the ~~see~~ WECC's Western Assessment of Resource Adequacy report~~, see Appendix E~~.

solar resources total 6,500 MW, which on a low availability end of the spectrum for resource availability, could expect to lose 5,500 MW or nearly 90% of this resource.

For this scenario, there were no new coal retirements included in this subregion. However, coal retirements that occurred in the other subregions did have an impact in the amount of energy available to transfer to CAMX.

Planning Reserve Margin

Given the growing variability, a 15% margin for the CAMX area is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 40%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 11,000 MW or 20% of the expected peak demand.

Risk Scenario Results

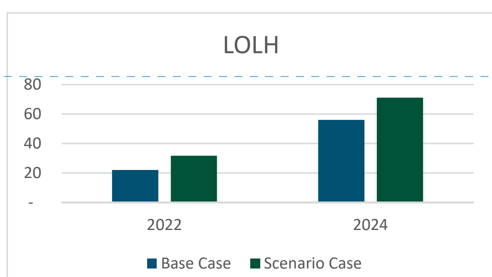
For the CAMX region, the Reliability Indices are summarized in Table 9.1, broken out by the CA region and the MX region. The Mexico portion of the CAMX region has seen a significant increase in their demand forecast since the 2018 ProbA was published. The annual energy demand forecast for 2022 was expected at around 15,900 GWh when reported for the 2018 Prob-A. In the 2020 Prob-A, the annual energy forecast has risen to approximately 16,900 GWh, a change of approximately 6.0%. This new demand forecast coupled with the California portion of the regions inability to transfer energy after the peak hours in the evening, due to their own shortfalls, has led to a significant increase in expected unserved energy for this region. Looking at the California portion of this region, the LOLH and EUE have improved since last probabilistic assessment with large improvements by 2024.

Table 9.1: Reliability Index Comparison – CAMX

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
California Only						
EUE [MWh]	26,930	29,266	2,336	6,886	36,164	29,278
EUE [ppm]	146	159	13	27	133	106
LOLH [hrs/yr]	0.8	0.8	0	0.15	0.74	0.59
Mexico Only						
EUE [MWh]	987,786	1,392,212	416,426	2,396,090	2,991,820	595,730
EUE [ppm]	3,622	5,152	1,530	8,793	10,846	2,053
LOLH [hrs/yr]	21	31	10	55	70	15

Annual Demand at Risk (DAR)[26]

In 2022, for the scenario, the CAMX subregion could experience as many as 32 hours where the ~~one~~ 1 day in 10~~ten~~ years LOLE threshold of resource adequacy is not maintained, and up to 71 hours by 2024. For the base case the results were 22 and 56 hours, respectively. Given the CAMX subregion will need to rely heavily on external assistance to maintain resource adequacy, the impacts to demand at risk of the scenario came from retirements in other subregions as no coal was retired in CAMX.



Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for CAMX causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the CAMX subregion is expected to

[26] WECC distinguishes the term Loss-of-Load Hours (LOLH) as "Demand at Risk (DAR)". The two terms here are synonymous

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Commented [WP112]: Please consider using LOLH instead of DAR to be consistent with the other graphs

Commented [JS113R112]: Added footnote to determine linkage between the two terms.

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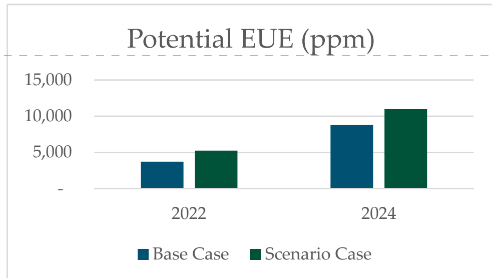
have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

Energy at Risk

In 2022, about 5,200 per million MWh of energy[27] is at risk in the scenario case and grows to nearly 11,000 per million MWh by 2024. In the base case, the results were 3,700 and 8,800 per million MWh, respectively. For the 32 hours of potential demand at risk in the scenario results, this would equate to approximately 162 per million MWh, on average, in 2022. For the 71 hours of potential demand at risk in the scenario results, this would equate to approximately 155 per million MWh, on average, in 2024.



WECC - Southwest Reserve Sharing Group (SRSG)

The SRSG subregion is a summer peaking area that consists of the entire states of Arizona and New Mexico and a portion of the states Texas and California.

Demand

The SRSG subregion is expected to peak in mid-July at approximately 26,100 MW in 2022 and 26,900 MW in 2024. Overall, the SRSG subregion should expect an 93% ramp, or 12,600 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 29,600 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 30,600 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 is 29,600 MW. Under low resource availability conditions, the SRSG subregion may only have 24,100 MW ~~available~~ to meet a 26,100 MW expected peak. The expected availability of resources on the peak hour in 2024 is 29,200 MW. Under low resource availability conditions, the SRSG subregion may only have 24,200 MW ~~available~~ to meet a 26,900 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

~~Variability is highly dependent on the resource type.~~ Although baseload resources account for roughly 25,000 MW of availability, the low availability end of the spectrum would only see a loss of 3,100 MW. Whereas, solar resources total 1,400 MW of availability, but on a low availability end of the spectrum ~~for resource availability~~, they could expect to lose 600 MW or nearly half of this resource.

For this scenario, there were approximately 400 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 16% margin for the SRSG subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 27%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 3,500 MW or 13% of the expected peak demand. As more

[27] Any reference to "per million MWh of energy" can be translated to a EUE in total MWh in the tables provided for each region.

Commented [JS114]: From Aran Narang (Hydro One): "Clarify what "5,200 per million MWH of energy" means – I'm having trouble understanding. "

Commented [JS115R114]: Updated to Tables as part of WECC's changes to section. Added footnote to show conversion is in the new table.

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Commented [WP118]: I don't think "for resource availability" is needed. If you think you do, then put it in the sentence above.

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variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the SRSG region, the Reliability Indices are summarized in Table 9.2.

Table 9.2: Reliability Index Comparison – SRSG						
Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
EUE [MWh]	11	212	201	81	437	356
EUE [ppm]	0.106	2.05	1.90	0.75	4.03	3.28
LOLH [hrs/yr]	0.001	147	146	0.004	22	22

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Annual Demand at Risk

In 2022, for the scenario, the SRSG subregion could experience as many as 14 hours where the 1~~one~~ day in 10~~ten~~ years LOLE threshold of resource adequacy is not maintained, and up to 22 hours by 2024. For the base case the results were less than an hour in both years. The impacts of the scenario came from the 400 MW coal retirement as well as impacts from external assistance in other subregions.

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Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for SRSG causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the SRSG subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

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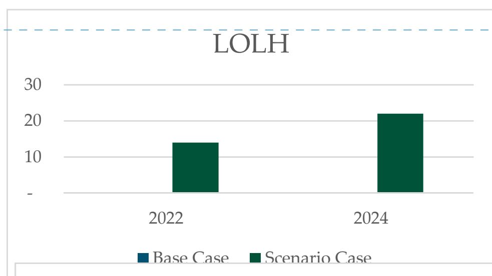
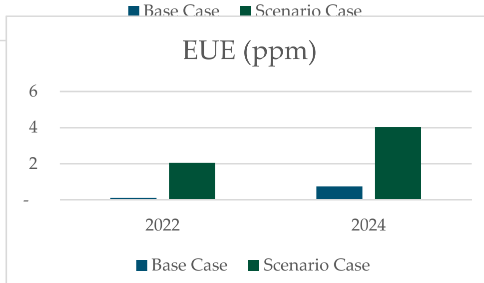


Energy at Risk

In 2022, about 2 per million MWh of energy is at risk in the scenario case and grows to nearly 4 per million MWh by 2024. In the base case, the results were less than 1 per million MWh for both years.



WECC - Northwest Power Pool – United States (NWPP-US)

The Northwest Power Pool – US subregion consists of the northern US and central portions of the Western Interconnection. This subregion is both summer and winter peaking depending on location. The area covers all the states of Washington, Oregon, Idaho, Nevada, Utah, Colorado, and Wyoming as well as portions of the states of Montana, California, South Dakota, and Nebraska.

Demand

The NWPP-US subregion is expected to peak in late-July at approximately 65,000 MW in 2022 and 66,100 MW in 2024. Overall, the NWPP-US subregion should expect an 81% ramp, or 29,100 MW, from the lowest to the highest demand hour of the peak demand day in 2022. In 2022, there is a 5% possibility the subregion could peak as high as 73,700 MW, which equates to a 13% load forecast uncertainty, and could peak as high as 75,500 MW in 2024.

Resource Availability

The expected availability of resources on the peak hour in 2022 and 2024 is 81,300 MW. Under low resource availability conditions, the NWPP-US subregion may only have 58,700 MW ~~available~~ to meet a 65,000 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

~~Variability is highly dependent on the resource type.~~ Although baseload resources account for roughly 50,200 MW ~~of availability~~, the low availability end of the spectrum would only see a loss of 8,800 MW. Whereas, solar resources total 3,600 MW of availability, but on a low availability end of the spectrum ~~for resource availability~~, they could expect to lose 2,000 MW or over half of this resource.

For this scenario, there were approximately 1,100 MW of additional coal retirements included in this subregion.

Planning Reserve Margin

Given the growing variability, a 15-21% margin for the NWPP-US subregion is close to the median level of reserve margin needed to maintain reliability, it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 18,200 MW or 28% of the expected peak demand. As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

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Risk Scenario Results

For the SRSG region, the Reliability Indices are summarized in Table 9.3.

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Table 9.3: Reliability Index Comparison – NWPP-US						
Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta
EUE [MWh]	12,799	14,681	1,882	248,573	274,091	25,518
EUE [ppm]	33	38	5	622	686	64
LOLH [hrs/yr]	0.25	0.28	0.03	4.4	6.2	1.8

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Annual Demand at Risk

In 2022, for the scenario, the NWPP-US subregion could experience less than one hour where the one day in ten years LOLE threshold of resource adequacy is not maintained and just over 6 hours by 2024. For the base case the results were less than an hour in 2022 and 4 hours in 2024. The impacts of the scenario came from the 1,100 MW coal retirement as well as impacts from external assistance in other subregions.

Hours at Risk

A system wide high demand scenario would eliminate much of the external assistance available for NWPP-US causing this to be exacerbated, and a low availability scenario would lead to a highly constrained external assistance scenario throughout the system. Even under expected conditions, the NWPP-US subregion is expected to have many hours where the one day in ten years threshold of reliability is not maintained through the inclusion of new resources and/or external assistance.

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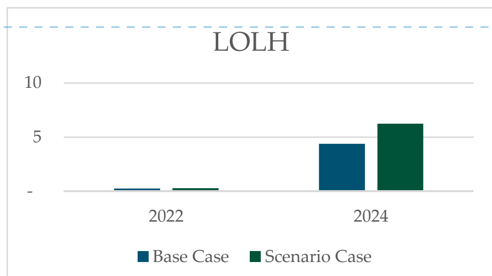
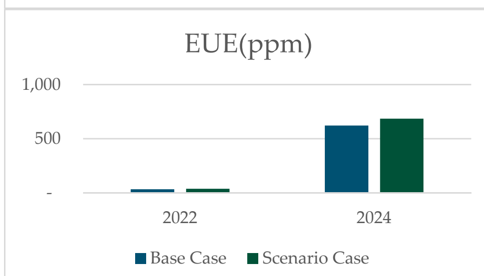


Energy at Risk

In 2022, about 37 per million MWh of energy is at risk in the scenario case and grows to nearly 685 per million MWh by 2024. In the base case, the results were 32 and 621 per million MWh respectively. For the 6 hours of potential demand at risk in the scenario results, this would equate to approximately 110 per million MWh on average in 2024.



WECC – Alberta & British Columbia (WECC-AB) & (WECC-BC)

The WECC-AB subregion covers the Alberta province of Canada while the WECC-BC subregion covers the British Columbia province. Both subregions are winter peaking.

Demand

The WECC-AB subregion is expected to peak in early-February at approximately 9,200 MW in 2022 and 2024. Overall, the WECC-AB subregion should expect an 30% ramp, or 2,100 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 9,500 MW, which equates to a 3% load forecast uncertainty.

The WECC-BC subregion is expected to peak in mid-January at approximately 9,300 MW in 2022 and 9,600 MW in 2024. Overall, the WECC-BC subregion should expect a 49% ramp, or 3,000 MW, from the lowest to the highest demand hour of the peak demand day. In 2022, there is a 5% possibility the subregion could peak as high as 10,000 MW, which equates to an 11% load forecast uncertainty.

Resource Availability

In the WEC-AB subregion the expected availability of resources on the peak hour in 2022 is 13,300 MW and 11,000 MW in 2024. Under low resource availability conditions, the WECC-AB subregion may only have 12,000 MW ~~available~~ to meet a 9,200 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 12,300 MW ~~of availability~~, the low availability end of the spectrum would only see a loss of 500 MW. Whereas, wind resources total 700 MW of availability, but on a low availability end of the spectrum ~~for resource availability~~, they could expect to lose all this resource.

In the WECC-BC subregion the expected availability of resources on the peak hour in 2022 and 2024 is 12,900 MW. Under low resource availability conditions, the WECC-BC subregion may only have 10,600 MW available to meet a 9,300 MW expected peak. Although there is only a 5% probability of this occurring, a large amount of external assistance would be needed to meet demand under low-availability conditions.

Variability is highly dependent on the resource type. Although baseload resources account for roughly 1,000 MW ~~of availability~~, the low availability end of the spectrum would only see a loss of 100 MW or 10%. Whereas, hydro resources total 11,800 MW ~~of availability~~, but on a low availability end of the spectrum ~~for resource availability~~, they could expect to lose 2,100 MW of this resource or about 20%.

For this scenario, there were approximately 800 MW of additional coal retirements included in the WECC–AB subregion, zero in WECC-BC.

Planning Reserve Margin

Given the growing variability, a 15% margin for the WECC-AB subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum needed for all hours. The highest reserve margin needed is expected to be around 22%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed equates to approximately 1,700 MW or 19% of the expected peak demand.

Given the growing variability, a 15% margin for the WECC-BC subregion is close to the median level of reserve margin needed to maintain reliability; it should not be considered the maximum for all hours. The highest reserve margin needed is expected to be around 42~~%.~~%,~~.%. Therefore, it is important to look at reserve margins in terms of MWs. The highest reserve margin needed~~ which equates to approximately 2,800 MW or 31% of the expected peak demand.

As more variable resources are added to the system, both on the demand side through roof-top resources and the resource side through generation plants, a larger reserve margin is needed to account for variability in the system.

Risk Scenario Results

For the scenario of both Canada subregions showed no expected LOLH or EUE. For the Canada subregions, the coal resource portion of the generation portfolio is small, and removal of these resources had little to no impact on the resource adequacy of these subregions~~.~~. This is based on the sum Table 9.4.

Table 9.1: Reliability Index Comparison – Alberta and British Columbia

Reliability Index	2022 Base Case	2022 Scenario	2022 Delta	2024 Base Case	2024 Scenario	2024 Delta

Alberta						
EUE [MWh]	0	0	0	0	0	0
EUE [ppm]	0	0	0	0	0	0
LOLH [hrs/yr]	0	0	0	0	0	0
British Columbia						
EUE [MWh]	19	0	-19	8	0	-8
EUE [ppm]	0.323	0	-0.323	0.137	0	-0.137
LOLH [hrs/yr]	0.001	0	-0.001	0.001	0	-0.001

Appendix A: Assessment Preparation, Design, and Data Concepts

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404-446-2560

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Assessment Data Questions
Please direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the *2020 NERC Probabilistic Assessment*[28]. However, extensive reproduction of tables and/or charts will require permission from NERC Staff and PAWG Members:

NERC Probabilistic Assessment Working Group (PAWG) Members

Name:	Organization:	Name:	Organization:
Andreas Klaube	Chair; NPCC	Julie Jin	ERCOT
Alex Crawford	Vice Chair; Southwest Power Pool, Inc.	Peter Warnken	ERCOT
John Skeath	North American Electric Reliability, Corp.	Sennoun Abdelhakim	Hydro-Québec
Salva Andiappan	Midwest Reliability Organization	Lewis De La Rosa	TRE
Guarav Maingi	SaskPower	David Richardson	Independent Electricity System Operator
Bagen Bagen	Manitoba Hydro	Vithy Vithyananthan	Independent Electricity System Operator
Darius Monson	Midcontinent Independent System Operator	Anna Lafoyiannis	Independent Electricity System Operator
Phil Fedora	NPCC	Richard Becker	SERC Reliability Corporation
Peter Wong	ISO New England, Inc.	Anaisha Jaykumar	SERC Reliability Corporation
Manasa Kotha	ISO New England, Inc.	Wyatt Ellertson	Entergy
Laura Popa	New York ISO	Patricio Rocha-Garrido	PJM Interconnection, L.L.C.
Sadhana Shrestha	New York ISO	Jason Quevada	PJM Interconnection, L.L.C.
Mike Welch	New York ISO	Tim FryFogle	ReliabilityFirst
Benjamin O'Rourke	New York ISO	William Lamanna	North American Electric Reliability, Corp.
Bryon Domgaard	WECC	Amanda Sargent	WECC
Matt Elkins	WECC		

[28] NERC_LTRA_2020.pdf

Appendix B: Description of Study Method in the ProbA

Descriptions and assumptions of each Region's probabilistic model are detailed in the sections below. Where a region is not listed, information was not provided at time of publication, but may be provided through contact via information listed in Appendix A.

MRO - MISO

General description

MISO utilized the Strategic Energy Risk Valuation Model (SERVM) to perform the 2020 ProbA base case and scenario. 30 historic weather years were modeled with 5 different economic uncertainty multipliers and 125 outage draws resulting in 18,750 unique load/outage scenarios being analyzed. In SERVM the MISO system was represented as a transportation model with each of MISO's 10 Local Resource Zones (LRZ's) modeled with their respective load forecasts and resource mixes. The LRZ's were able to import and export energy with each other within the model and the results of the study were aggregated up to the MISO level.

Demand & LFU

To account for load uncertainty due to weather, MISO modeled 30 unique load shapes based on historic weather patterns. These load shapes were developed using a neural-net software to create functional relationships between demand and weather using the most recent 5 years of actual demand and weather data within MISO. These neural-net relationships were then applied to the most recent 30 years of weather data to create 30 synthetic load shapes based on historic weather. Finally, the average of these 30 load shapes was scaled to the 50-50 forecasts from MISO's Load Serving Entities (LSE's).

To capture economic uncertainty in peak demand forecasts, MISO modeled each of the 30 load shapes with 5 different scalars (-2%, -1%, 0%, 1%, 2%). This resulted in 150 unique load scenarios (30 load shapes X 5 uncertainty scalars) being modeled.

Thermal Resources

All thermal resources in MISO were modeled as 2-state units ~~i.e.~~i.e., either dispatched to full installed capacity or offline. Units with at least 1 year of operating history were modeled with their actual EFORd based on GADS data (up to 5 historic years). Units with insufficient operating history to determine an EFORd were assigned the class average EFORd.

Wind & Solar

Wind units were modeled with monthly ELCC values which can be found in MISO's 2021-22 PY LOLE Study Report. Solar resources were modeled at 50% of installed capacity. Both wind and solar were treated as a net-load reduction within the model.

Hydroelectric

Hydro units in MISO were modeled as a resource with an EFORd except for run of river units. These were modeled at their individual capacity credit which is determined by the ~~resources~~resource's historic performance during peak hours.

Demand-side resources

Demand Response was modeled as dispatchable call limited resources. These resources were only dispatched when needed during emergency conditions to avoid shedding load. Energy Efficiency resources were modeled as load modifiers which were netted from the load within the model.

Transmission
Capacity Import Limits (CIL) and Capacity Export Limits (CEL) were modeled for each of the 10 LRZ's. If a LRZ was expected to be unable to meet its peak demand, then that zone would import capacity up to its CIL provided there was sufficient exports available from other zones.

MRO - SaskPower
General description
Saskatchewan utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE).
Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance, and outages are included in the model. The model simultaneously considers many types of randomly occurring events such as forced outages of generating units. Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 34.2 % and 30.0 %, for years 2022 and 2024 respectively. EUE calculated for base case is 80.4 MWh and 26.4 MWh for the years 2022 and 2024, respectively. LOLH follows a similar pattern to EUE.

Demand & LFU
This reliability study is based on the 50:50 load forecast that includes data such as annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model forecasted industrial load data, and weather normalization model.

The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses. Load Forecast Uncertainty is explicitly modeled utilizing a seven-step normal distribution with a standard deviation of $\pm$ 3%, 5% and 10%.

Thermal Resources
Natural gas units are typically modeled as a two-state unit so that gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as a three-state unit. Coal unit can be at a full load, a derated forced outage or a full forced outage state. Forecast derated hours are based on the percentage of the time the unit was derated out of all hours, excluding planned outages, based on the 5-year historical average. Generally, we use UFOP when forecasting reliability for the gas turbine units and FOR/DAFOR for the Steam units.

Wind & Solar
For reliability planning purposes, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand. Two methods were utilized to carry out the analysis for determining wind capacity credit. First method approximates the Effective Load Carrying Capability (ELCC) of the wind turbines by determining the wind capacity during peak load hours of each month by looking at historical wind generation in those hours. A period of 4 consecutive hours was selected and the actual wind generation in those 4 hours was used to determine the ELCC of the wind turbines. The median capacity value of wind generation in those 4 hours of each day of the month is calculated and is converted to a percent capacity by dividing that number by the maximum capacity of the wind turbine. Another method to estimate the ELCC was also utilized by looking at the top 1%, 5%, 10% and 30% of load hours in each month. Using these methods, we then looked at the lowest averages in each of the winter and summer months to come up with the wind capacity credit value.

Currently, Saskatchewan has low penetration level of Solar resources and most of it is Distributed Energy Resource (DER), which is netted off the load forecast.

Hydroelectric

Hydro generation is modeled as energy limited resource and the annual hydro energy is calculated based on the historical data that has been accumulated over the last 30 plus years. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy are then scheduled to reduce the peak loads as much as possible.

Demand-side resources

***Controllable and Dispatchable Demand Response Program**:* Demand Response is modelled as an Emergency Operating Procedure by assigning a fixed capacity value (60 MW) and thus configured as a negative margin state for which MARS evaluates the required metrics. An Emergency Operating Procedure is initiated when the reserve conditions on a system approach critical level.

Energy provided from Energy Efficiency (EE) and Conservation programs is netted off the load forecast.

Transmission

No transmission facility data is used in this assessment as the model assumes that all firm capacity resources are deliverable within the assessment area. Separate transmission planning assessments indicate that transmission capability is expected to be adequate to supply firm customer demand and planned transmission service for generation sources.

MRO - SPP

General description

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million. SPP assessment area has over 90,000 MW (name plate) of total generation, which includes over 28,000 MW of nameplate wind generation. SPP is also a summer peaking assessment area at approximately 51,000 MW of summer peak demand.

Demand & LFU

Eight years (2012-2019) of historical hourly load data were individually modeled to produce 8,760 hourly load profiles for each zone in the SPP Assessment Area. In order to not overestimate the peak demand, the forecasted peak demand for 2022 and 2024 were assigned to the load shape from 2014 (the median year of the eight historical years). The other seven years were also scaled to a forecasted peak demand calculated by distributing the variance between the peaks of the non-median years to the median year.
Microsoft Excel was used to regress the daily peak values against temperatures, economics, and previous daily peak loads observed at key weather stations throughout the SPP footprint to derive the load forecast uncertainty components. The load multipliers were determined from a uniform distribution and assigned seven discrete steps with the applicable probability occurrence weighting. All seven of the load forecast uncertainty steps were modeled at or above the 50/50 peak forecast.

Thermal Resources

SPP modeled seasonal maximum net capabilities reported in the LTRA for thermal resources. Physical and economic parameters were modeled to reflect physical attributes and capabilities of the resources. Full and partial forced outages from NERC GADS data in the SPP footprint were applied on a resource basis.

Wind & Solar

SPP included wind and solar resources currently installed, under construction, or that have a signed interconnection agreement. Wind and solar resources were modeled in SERVM with an hourly generation profile assigned to each individual resource. Hourly generation is based upon historical profiles correlating with the yearly load shapes (2012 to 2019). Any resources that did not have historical shapes were supplemented by the nearest resource.

Hydroelectric

Hydro generation was modeled as energy limited resources while considering monthly hydro energy limitations calculated using historical data from 2012 to 2019. Hydro resources also considered historical daily max energies and the software dispatched by the resources as needed to maintain reliability.

Demand-side resources

Controllable and dispatchable demand response programs were modelled as equivalent thermal units with high fuel costs so that those units would be dispatched last to reflect demand-response operating scenarios to prevent loss of load events.

Transmission

The SPP transmission system was represented as “pipes” between six zones modeled in the SPP Assessment Area. A First Contingency Incremental Transfer Capability analysis was performed outside of the SERVM software which determined transfer limits modeled between zones. All resources and loads in their respective zone were modeled as a “copper sheet” system.

NPCC- Maritimes

General description

The Maritimes assessment area is winter peaking and part of NPCC with a single RC and two BA areas. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, Prince Edward Island, and the northern portion of Maine, which is radially connected to NB. The area covers 58,000 square miles with a total population of 1.9 million.

Demand & LFU

Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modeling, and end-use modeling to develop their load forecasts. Annual peak demand in the Maritimes area varies by +9% of forecasted Maritimes area demand based upon the 90/10 percentage points of LFU distributions.

Thermal Resources

Maritimes area uses seasonal dependable maximum net capability to establish combustion turbine capacity for resource adequacy. During summer, these values are derated accordingly.

Wind

The Maritimes area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the 2012–2018 period. The wind in any hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area’s actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts represents the Maritimes area’s hourly wind forecast.

Solar

Solar capacity in the Maritimes area is BTM and netted against load forecasts. It does not currently count as capacity.

Hydroelectric

Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.

Demand-side resources

Plans to develop up to 120 MW by 2029/2030 of controllable direct load control programs by using smart grid technology to selectively interrupt space and/ or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist. During this 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 196 MW while the annual amounts for winter peak demand reductions rise from 93 MW to 465 MW.

Transmission

Construction of a 475 MW +/-200 kV HVDC undersea cable link (the Maritime Link) between Newfoundland and Labrador and Nova Scotia was completed in late 2017; this cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in Nova Scotia in 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern New Brunswick area.

Other

The current amount of DERs in the Maritimes area is currently insignificant at about 29 MW in winter. During this LTRA period, additions of solar (mainly rooftop) resources in Nova Scotia are expected to increase this value to about 184 MW. The capacity contribution of rooftop solar during the peak is zero as system winter peaks occur during darkness. As more installations are phased in, operational challenges, like ramping and light load conditions, will be considered and mitigation techniques investigated.

NPCC- New England

General description

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning process for the regional BPS. The New England BPS serves approximately 14.5 million people over 68,000 square miles.

Demand & LFU

ISO-NE develops an independent demand forecast for its BA area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecast are considered coincident. This demand forecast is the gross demand forecast that is then decreased to a net forecast by subtracting the impacts of EE measures and BTM PV. Annual peak demand in the New England area varies by +11% of forecasted New England area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The seasonal claimed capability as established through claimed capability audit is used to rate the sustainable maximum capacity of nonintermittent thermal resources. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during ISO-NE defined seasonal reliability hours.

Wind

New England models wind resources use the seasonal claimed capability that is based on their historical median net real power output during seasonal reliability hours.

Solar
Most of the solar resource development in New England consists of the state-sponsored distributed BTM PV resources that do not participate in the wholesale electricity markets but reduce the real-time system load observed by ISO-NE system operators. These resources are modeled as load modifiers on an hourly basis based on the 2002 historical hourly weather profile.

Hydroelectric
New England uses the seasonal claimed capability to represent hydroelectric resources. The seasonal claimed capability for intermittent hydro-electric resources is based on their historical median net real power output during seasonal reliability hours.

Demand-side resources
On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Currently, approximately 584 MW of DR participates in these markets and is dispatchable (i.e., treated like generators). Regional DR will increase to 592 MW by 2023 and this value is assumed constant/available thru the remainder of the assessment period.

Transmission
The area has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While several major projects are nearing completion, two significant projects remain under construction: Greater Boston and Southeastern Massachusetts and Rhode Island (SEMA/RI). The majority of the Greater Boston project will be in-service by December 2021 while the addition of a 115 kV line between Sudbury and Hudson is expected to be in service by December 2023. The SEMA/RI project is in the early stages of construction. Additional future reliability concerns have been identified in Boston and are being addressed through a development request-for-proposal.

Other
New England has 174 MW (1,379 MW nameplate) of wind generation and 787 MW (2,164 MW nameplate) of BTM PV. Approximately 12,400 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,062 MW (4,306 MW nameplate) by 2029. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decreasing from 34.3% of nameplate in 2020 to about 23.8% in 2029.

NPCC- New York
General description
The NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The transmission grid of New York State encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.5 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013.

Demand & LFU
The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly in the forecast model with additional adjustments for policy-driven EE impacts made where needed. The impacts of DERs, EVs, other electrification, energy storage, and BTM solar PV are made exogenous to the model. At the system level, annual peak demand forecasts range from 6% above the baseline for the ninetieth percentile forecast to 8% below the baseline for the tenth percentile forecast. These peak forecast variations due to weather are reflected in the LFU distributions applied to the load shapes within the MARS model.

Thermal Resources

Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW values. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an EFORd.

Wind

New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Solar

New York provides 8,760 hours of historical solar MW profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by randomly selecting an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted.

Hydroelectric

Large New York hydro units are modeled as thermal units with a corresponding multistate representation that represents an EFORd. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by randomly selecting an annual shape for each run-of-river unit in each draw. Each shape is equally weighted.

Demand-side resources

The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance.

Transmission

The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the RPP inclusion rules. The NYISO Board of Directors selected projects under two public policy transmission planning processes: the first for Western New York and the second for Central New York and the Hudson Valley, which is known as the ac transmission need. When completed, these projects will add more transfer capability in Western New York and between Upstate and Downstate New York.

Other

The NYISO is currently implementing a 3–5-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined NYISO's vision for DER market integration. The FERC approved the NYISO's proposed tariff changes in January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2021[29].

Commented [JS126]: From David Jacobson:
"The description labelled "Other" perhaps should be combined with "Solar".

Commented [AC127R126]: Further clarification would need to be provided by NPCC staff

Commented [AK128R126]: There are many types of DER in addition to solar. A footnote was added to clarify why "Other" is used.

NPCC- Ontario

General description

The IESO is the BA for the province of Ontario. The province of Ontario covers more than one million square kilometers (415,000 square miles) and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC–New York.

[29] Distributed Energy Resources (DER) - NYISO

Demand & LFU

Each zone has an hourly load from the demand forecast, as well as a monthly load forecast uncertainty (LFU) distribution. The LFU is derived by simulating the effect of many years of historical weather on forecasted loads. Monthly distributions of simulated demand peaks are generated at a zonal level and then adjusted to match the equivalent distribution at the provincial level.

The adjusted LFU distributions are used to create a seven-step approximation of the actual distribution. When generating reliability indices, the MARS model assesses all seven steps of the LFU distribution, weighted by probability. Annual peak demand in the Ontario Area varies by +11% of forecasted Ontario area demand based upon the 90/10% points of LFU distributions.

Thermal Resources

The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Wind

Historical hourly load profiles are used to model wind generation. Wind generation is aggregated by zone. For the Monte Carlo analysis, the model randomly selects a different yearly simulated profile during each iteration.

Solar

Historical hourly profiles are used to model solar generation. Solar generation is aggregated by zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production.

Hydroelectric

Hydroelectric generation is modelled using three inputs: a run-of-river component, which simulates the range of historical water availability, a maximum dispatchable capacity, and a dispatchable energy. Input values are calculated using a combination of historic hourly maximum offer data and historic hourly production data, aggregated on a zonal level. The three inputs work together to simulate the range of historical water conditions that have been experienced since market opening in 2002.

Demand-side resources

The IESO models two demand-side resources as a supply resource: demand response (DR) and dispatchable loads (DL). Both measures are modelled on an as-needed basis in MARS and will only be used when all other supply-side resources are insufficient to meet demand. DR and DL capacity is aggregated by IESO zone.

Transmission

The IESO-controlled grid is modelled using 10 electrical zones with connecting transmission interfaces. Transmission transfer capabilities are developed according to NERC standard requirements; the methodology for developing transmission transfer capabilities is described in the IESO's "Transfer Capability Assessment Methodology: For Transmission Planning Studies.

NPCC- Quebec

General description

The Québec assessment area (province of Québec) is winter-peaking and part of NPCC. It covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

Demand & LFU

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The Quebec area demand forecast average annual growth is 0.8% during the 10-year period. Annual peak demand in the Quebec area varies by +9% of forecasted Ontario area demand based upon the 90/10% points of load forecast LFU distributions.

Thermal Resources

For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.

Wind

In Quebec, wind capacity credit is set for the wintertime as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100%.

Solar

In Québec, BTM generation (solar and wind) is estimated at approximately 10 MW and doesn't affect the load monitored from a network perspective.

Hydroelectric

In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Demand-side resources

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,730 MW on Winter 2020–2021 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will have an impact of 310 MW in 2020–2021, 150 MW for Winter 2021–2022, and then growing to 300 MW by 2026–2027. Another similar program for residential customers is under development and should gradually rise from 57 MW for Winter 2020–2021 to 621 MW for Winter 2030–2031.

Transmission

The Romaine River Hydro Complex Integration project is presently underway; its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015, and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) was planned be in service in 2020, but its commissioning is delayed to 2022. A new 735 kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean is now under construction phase and is planned to be in service in 2022. The project also includes adding equipment to both substations and expanding Saguenay substation.

Other

Total installed BTM capacity (solar PV) is expected to increase to more than 500 MW in 2031. Solar PV is accounted for in the load forecast. Nevertheless, since Quebec is a winter-peaking area, DERs on-peak contribution ranges from 1 MW for Winter 2020–2021 to 10 MW for Winter 2030–2031. No potential operational impacts of DERs are expected in the Quebec area, considering the low DER penetration in the area.

SERC

General description

SERC covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC utilizes General Electric (GE) Multi-area Reliability Simulation (MARS) software an ~~8,760 hourly~~8,760-hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of fifteen interconnected areas, four of which are SERC's NERC Assessment Areas (SERC-E, SERC-C, SERC-SE, and SERC-FP). All assumptions and methods are described below and apply to the assessment areas.

Demand & LFU

For this study, annual load shapes for the seven years between 2007 and 2013 were used to develop the Base Case load model. Each of the hourly load profiles developed from the historical loads were then adjusted to model the seasonal peaks and annual energies reported in the 2020 SERC LTRA filings. Except for SERC-FP, all assessment areas are winter peaking. This study accounted for LFU in two ways. The first was to utilize seven different load shapes, representing seven years of historical weather patterns from 2007 through 2013. The second way is through multipliers on the projected seasonal peak load and the probability of occurrence for each load level. Annual peak demand varies by the following load forecast uncertainty, SERC-C: 4.75%, SERC-E: 3.95%, SERC-SE-6.11%, SERC-FP: 4.04%.

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Thermal Resources

The three categories modeled in this study were thermal, energy-limited, and hourly resources. Most of the generating units were modeled as thermal units, for which the program assumes that the unit is always available to provide capacity unless it is on planned or forced outage. All the thermal units were modeled with two capacity states, either available or on forced outage.

The data for the individual units modeled in the SERC assessment areas was taken from the 2020 LTRA filings.

Wind & Solar

Wind and solar profiles for the units in the SERC footprint were represented using hourly generation time series. To represent the 2007-2013 meteorology, corresponding to the historical hourly load profiles, simulated production profiles were used. These profiles were extracted from available datasets from the National Renewable Energy Laboratory (NREL).

Five distinct sites were chosen for each assessment area, to represent existing wind farm locations. Similarly, five locations per SERC MRA were selected to create the solar profiles. Each site data was converted to power and aggregated to produce a typical solar shape per assessment area. To improve the robustness of the results, the study team used a 7-day sliding window method in the selection of wind and solar data.

Hydroelectric

MARS schedules the dispatch of hydro units in two steps. The minimum rating of each unit is set to 20% of the nameplate capacity, which represents the run-of-river portion of the unit and is dispatched across all hours of the month. Any remaining capacity and energy are then scheduled on an hourly basis as needed to serve any load that cannot be met by the thermal generation on the system. For hydro units, which are modeled as energy limited resources, their capacity factors (the ratio of the energy output to the maximum possible if operated at full output for all of the hours in the period) are an indication of their contribution to meeting load. Energy limited resources have a zero forced-outage rate.

The hydro unit data was extracted from the ABB Velocity Suite database and then adjusted to match the seasonal ratings of the units from the 2020 LTRA data. The monthly energy available is the average over the last 10 years of generation for each plant.

Demand-side resources

Demand-side resources are incorporated as an Energy Limited Resource with an annual energy megawatt hour limitation. These resources will be second in priority to thermal and variable generation to serve load. Demand response is modeled for all SERC assessment areas. For externals areas, these resources are modeled as emergency operating procedures, using the values from their LTRA submissions.

Transmission

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of area. First Contingency Incremental Transfer Capability Values for interface limits are modeled for the system. The assumption within areas is a copper sheet system (full capacity deliverability).

Texas-RE-ERCOT

General description

The Electric Reliability Council of Texas (ERCOT) region encompasses about 75 percent of the land area in Texas. The grid delivers approximately 90 percent of the electricity used by more than 26 million consumers in Texas. The probabilistic assessment using Strategic Energy Risk Valuation Model (SERVM) captured the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables. The model performed 10,000 hourly simulations for each study year to calculate physical reliability metrics. The 10,000 hourly simulations were derived from 40 weather years, 5 load forecast multipliers, and 50 Monte Carlo unit outage draws.

Demand & LFU

ERCOT developed a 50/50 peak load forecast which represented the average peak load from 40 synthetic load profiles, each representing the expected load in a future year given the weather patterns from each of the last 40 years of history. Annual peak demand in ERCOT varied by +2.1% based upon the 90th percentile distribution. Each synthetic weather year was given equal probability of occurring. Five load forecast uncertainty multipliers were applied to each of the 40 synthetic weather years. The multipliers, which range from -4% to +4%, captured economic load growth uncertainty.

Thermal Resources

Conventional generators were modeled in detail with maximum capacities, minimum capacities, heat rate curves, startup times, minimum up and down times, and ramp rates. The winter and summer capacity ratings were based on ERCOT's LTRA Report. SERVM's Monte Carlo forced outage logic incorporated full and partial outages based on historical operations.

Wind & Solar

Wind and solar resources were modeled as capacity resources with 40 historical weather years consisting of hourly profiles which coincide with the load and hydro years. The assumed peak capacity contributions for reserve margin accounting were 63% for coastal wind, 29% for panhandle wind, 16% for other wind, and 76% for solar. The actual reliability contributions were based on the hourly modeled profiles.

Hydroelectric

Dispatch heuristics for hydro resources were developed from eight years of hourly data provided by ERCOT, applied to 40 years of monthly data from FERC 923 and ERCOT, and modeled with different parameters for each month, including total energy output, daily maximum and minimum outputs, and monthly maximum output. A separate energy-limited hydro resource was modeled to represent additional capability during emergency conditions.

Demand-Side Resources

Interruptible load and demand response resources were captured as resources with specific price thresholds at which each resource is dispatched. These resources were also modeled with call limits and Energy Emergency Alert (EEA) level.

Transmission

SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple zones using a transportation/pipeline representation. ERCOT was modeled as a single region with ties to SPP, Entergy, and Mexico to reflect historical import/export activity and potential assistance. 1,220 MW of high voltage direct current interties were included in this study.

WECC

General description

The Multiple Area Variable Resource Integration Convolution (MAVRIC) model was developed to capture many of the functions needed in the Western Interconnection for probabilistic modeling. The Western Interconnection has many transmission connections between demand and supply points, with energy transfers being a large part of the interconnection operation. A model was needed that could factor in dynamic imports from neighboring areas. The Western Interconnection has a large geographical footprint, with winter-peaking and summer-peaking load-serving areas, and a large amount of hydro capacity that experiences large springtime variability. The ability to study all hours of the year on a timely run-time basis was essential for the probabilistic modeling of the interconnection. Additionally, the large portfolio penetration of Variable Energy Resources (VER), and the different generation patterns depending on the geographical location of these resources, called for correlation capability in scenario planning. MAVRIC is a convolution model that calculates resource adequacy through Loss-of-Load Probabilities (LOLP) on each of the stand-alone (without transmission) load-serving areas. The model then calculates the LOLP through balancing the system with transmission to a probabilistic LOLP. Finally, MAVRIC can supply hourly demand, VER output, and baseload generation profiles that can be used in production cost and scenario planning models. Figure B.1 provides the ~~high level~~high-level logic diagram of the processes MAVRIC performs.

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the calculations depends on the system and the desired output that is being analyzed. The MAVRIC model was developed to enhance the probabilistic capabilities at WECC. It allows WECC to perform independent reliability assessments of the Western Interconnection, a system that is geographically diverse and dependent on transfer capabilities. Using convolution techniques and Monte-Carlo simulations, and with the ability to use transfers dynamically, the tool models the overall resource adequacy of the Western Interconnection while maintaining adequate run-time and computing capabilities.

Demand & LFU

Probability distributions for the demand variability are determined by aligning historical hourly demand data to each of the Balancing Authorities in the database. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of the three weeks before and three weeks after the given hour for each of the historical years. The output is a series of hourly percentile profiles with different probabilities of occurring.

Thermal Resources

The distributions of the baseload resources, nuclear, coal-fired, gas-fired, and in some cases, biofuel and geothermal resources is determined by using the historical rate of unexpected failure and the time to return to service from the NERC Generation Availability Data System (GADS). Generator operators submit data that summarizes expected and unexpected outages that occur to their generating units. The annual frequency and recovery time for the unexpected outages is used to calculate the availability probability distributions for baseload resources. Through Monte-Carlo random sampling, MAVRIC performs 1,000 iterations for each resource, calculating the available capacity on an hourly basis for all hours of a given year. The model randomly applies outages to units throughout the year adhering to the annual frequency of outage rates for those units. Once a unit is made unavailable, the mean time to recovery is adhered to, meaning for a certain period of hours after the unexpected failure, that unit remains unavailable. The total available baseload capacity for each load serving area for each hour, is then ~~computed~~computed, and stored as a sample in a database. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. The output of this process is consistent with the VER distributions, in that a series of hourly percentile profiles with different probabilities of occurring is produced.

Wind & Solar / Hydroelectric

Determining the availability probability distributions for the VERs (water, wind, and solar-fueled resources), is conducted like the demand calculations but with two notable differences. The first, and most significant, difference is the time frame used in calculating the VER availability probability distributions. For VER fuel sources, the day of the week does not influence variability, as weather is variable weekday or weekends. Therefore, the need to use the data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days of the scenario. The other difference is that the historical generation data is compared against the available capacity to determine the historical capacity factor for that hour to be used in the percentile probability calculation. The output of this process is a series of hourly percentile profiles with different probabilities of occurring.

Demand-side resources

A significant portion of the controllable Demand Response/Demand-Side Management (DR/DSM) programs within the Western Interconnection are associated with large industrial facilities, air conditioner cycling programs, and water pumping – both canal and underground potable water and for irrigation. These programs are created by Load Serving Entities (LSEs) who are responsible for their administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in the Western Interconnection often have limitations such as limited number of times they can be called on and some can only be activated during a declared local emergency. Entities within WECC are not forecasting significant increases in controllable demand response.

Transmission

MAVRIC goes through a step-by-step balancing logic where excess energy, energy above an area's planning reserve margin to maintain the resource adequacy threshold, can be used to satisfy another area's resource adequacy shortfalls. This is dependent on the neighboring areas having excess energy as well as there being enough transfer capability between the two areas allowing the excess energy to flow to the deficit area. MAVRIC analyzes first order transfers, external assistance from an immediate neighbor, and second order transfers, external assistance from an immediate neighbor's immediate neighbors, in all cases checking for sufficient transfer capacity. After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system where needed. The end result is an analysis of the entire system reflecting the ability of all load-serving areas to maintain a resource adequacy planning reserve margin equal to or less than the threshold. Analysis is then done on any areas where the threshold margin cannot be maintained even after external assistance from excess load-serving areas.

Other

Planning Reserve Margins - For each hour the demand and availability distributions are compared to one another to determine the amount of "overlap" in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions represents the LOLP. This would be the accumulative probability associated with the overlap. If the probability is greater than the selected threshold, then there is a resource adequacy shortfall in that area for that hour. A resource adequacy threshold planning reserve margin can be determined to identify the planning reserve margin needed to maintain a level of LOLP at or less than the threshold.

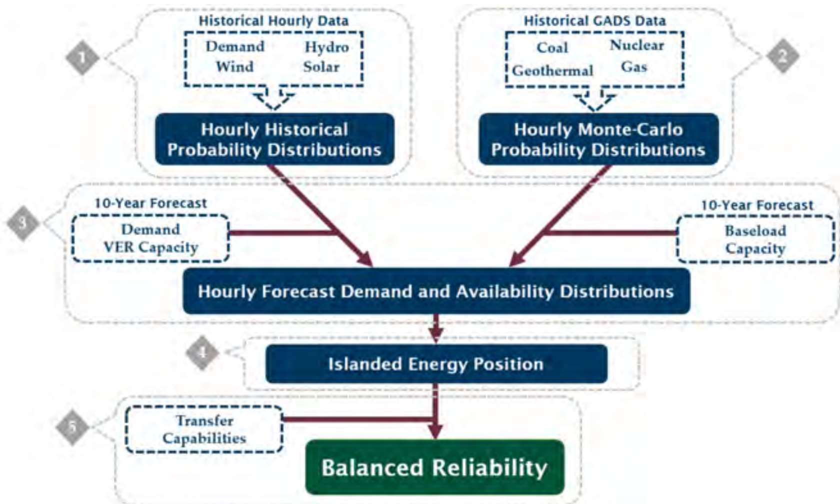

Figure B.1: MAVRIC Process Flowchart

Appendix C: Summary of Inputs and Assumptions in the ProbA

		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	**Name**	GE MARS	GE MARS	GE MARS	GE-MARS	GE MARS	GE MARS	SERVM	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*7	1,000*7	1,000*10*7	50000 * 7	10000	20000 x 7	28,000	50 x 40 x 5	N/A
	Total Run Time	2 hours * 72 CPUs	2 hours * 40 CPUs	50 min * 720 CPUs	3 Hours	35 min	0.5 hours	30 hours/Study Year; 35 processors	7 hours; 25 cores	N/A
Load	**Internal Load Shape**	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	07 yrs.; 2007-2013; Risk-based weighted load shapes	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak (2008)	8 historical years (2012 to 2019)	40 weather years 1980 to 2019	2004-2014
	External Load Shape	Typ. Yr. S-2002; W-2004	Typ. Yr. S-2002; W-2004	2007-2013 using ProbA data sheets & PJM model	N/A	Typical year 2002	None	No External Areas represented	40 weather years 1980 to 2019	N/A
	Adjustment to Forecast	Monthly Peak & Energy	Monthly Peak	Seasonal Peaks	Monthly Peaks	Monthly Peak & Energy	Monthly Peaks and Energy	Annual Peak	Annual Peak	N/A

Commented [JS129]: From David Jacobson:
"I really like the ability to compare each other's' major inputs and assumptions. Does the WG discuss pros/cons of each other's methods as feedback for the next assessment? For example, if I pick on load shape. Some use a typical year of 2002. Some use 40 years of data. I believe MISO uses 30 different load shapes from a particular year. Could a 20-year load shape be considered "stale" if there have been major changes to load like behind the meter generation? It might be useful to have a comment/suggestion column in the table to note where entities may want to make changes – or this info could remain internal to the WG – up to you."

Commented [JS130R129]: The task is useful, and the discussions mentioned in the comment are currently undertaken in the PAWG meetings. The working group also has documents on modeling and data inputs. The working group will consider this as a possible addition to the work plan.

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Load Forecast Uncertainty	**Modeling**	7-step Discrete Distribution	7-step Discrete Distribution. Monthly	Weather: 7 years	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps all steps at or above a 50/50 forecast	40 weather years x 5 load forecast uncertainty multipliers = 200 load scenarios	3%-97% probability distribution
Load Forecast Uncertainty	**90th %ile (% above 50/50 peak)**	Varies by Area; asymmetrical	2022-6%; 2024-6%	7.56% at 90%ile (1.28 Standard Deviation)	5.11%	2018-3.9% 2020-5.2%	2020-2.6%; 2018-2.6%	+5% at 99%ile	+2.1% at 90%ile	Varies by Region
Load Forecast Uncertainty	**Uncertainties Considered**	weather, economic, forecast	Weather, Forecast	Weather Forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	Weather, economic, forecast	Weather, Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	**Percentage of Peak Load at Peak**	Unknown	2022-1.9%; 2024-2.6%; Solar only	Minimal; ~1%	N/A	N/A	0	Minimal; Less than 1%	Resource	N/A
Behind-the-Meter	**Thermal Generation**	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Mix; Resource and Netted from Load	Resource	N/A
Behind-the-Meter	**Variable Generation**	Resource	Netted From Load	Within the load	Resource	N/A	N/A	Netted from Load	Resource	N/A

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Demand Management	Resource	Netted From Load	Within the load	Resource	NA	N/A	Netted from Load	Resource	N/A
Demand-Side Management	**Modeling**	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Operating Procedure	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchable Resource	N/A
	Load shape / Derates /FOR	N/A	N/A	Flat Seasonal	Count and Duration Limited	Reduction in Peak	None	None	Operation Count Limited	N/A
	Correlation to load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	not explicitly modeled	NA	None	Not Modeled	Dispatched based on shadow price	N/A
Variable Generation - Wind	**Modeling**	Resource, Fixed resource	Resource	Load Modifier	Load Modifier	Resource	Load Modifier	Resource	Resource	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	Weekly	Hourly Shape	Hourly Shape for 40 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	Consistent with load	Not Modeled	Consistent with load	Match load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	~11%	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	Ranges from 10% to 30% for Summer Peak depending on historical year and resource location	63% for coastal wind, 29% for panhandle wind, and 16% for other wind	Varies by Region
Variable Generation - Solar	**Modeling**	Resource	Resource	Load Modifier	Load Modifier	None	None	Resource	Resource with hourly profiles	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Monthly	Modeled at capacity credit value	NA	N/A	Hourly Shape	Hourly for 40 years matching load profile	Hourly Shape

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Flat	Not Modeled	NA	N/A	Consistent with load	Yes, same weather	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	94%	MISO System Capacity Credit is 50%	NA	N/A	Ranges from 80% to 100% for Summer Peak depending on historical year	76% for Summer Peak	Varies by Region
Hydro - Electric Generation	**Modeling**	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, Dispatched after Thermal to reduce LOLE	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource, Peak Shaving	Energy Limited Peak Shaving Component	Energy Limited Peak Shaving Component and Emergency Component	Energy Limited Resource
	Energy Limits	Average	N/A	Average 10 years monthly output	Summer Months, Peak Hours 14 - 17 HE	Different below average water conditions including extreme drought	Median	8 years of historical hydro conditions were modeled 2012-2019	40 years of historical hydro conditions were modeled for 1980-2019	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Model scheduled	Netted out based on modeling actual monthly hydro energies	Varies by Region
	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Within Capacity Derates	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	MC; 2-state	MC 2-state	MC up to 5 state	MC; Up to n-state	MC; 50 iterations of annual simulations with unique forced outage draws performed for each weather year and load forecast error	2-State 3%-97% Probability Distribution

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Energy Limits	None	None	None	None explicitly	None	None	None	None	None
	Capacity Derates	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Weekly	Used a summer capacity and a winter capacity value for each unit	Seasonal
	Planned Outages	By model, External Input	By Model	By Model	By Model	By Model	By Model & Manual Input	By Model	By Model calibrated to total historical planned outages	By Model
	Forced Outages	EFORd	5 yr. EEFORd	EFORd	5 yr. unit specific EFORd	EFORd	5-year historical average	5-year EFOR GADS Data	5-year EFOR GADS Data; Historical Events Modeled Discretely	Historical 12-year EFOR
Firm Capacity Transfers	**Modeling**	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource; Exports added as load	Import treated as load modifier	Explicitly Modeled	Not Modeled. All firm resources are modeled inside the ERCOT zone.	Explicitly Modeled
	Hourly Shape Issues	None	None	N/A	None	Weekly capacities	Hourly Load modification for a typical week.	None	N/A	N/A
	Capacity Adjustments - Transmission Limitations	None	None	N/A	None	None	N/A	N/A	N/A	N/A

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	None	Accounted for in interface limits	N/A	N/A	N/A	N/A
	Forced Outages	N/A	No	No	5 yr. unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	**Assessment Areas**	5	1	7	1	1	1	1	1	6
Internal Representation	**Total Nodes**	56	5	7	10	1	1	6	1	49
Internal Representation	**Node Definition**	Determined by potentially limiting transmission interfaces	Market-Defined Regions	Assessment Areas = Nodes	Local Resource Zone	N/A	N/A	Determined by potentially limiting transmission interfaces	N/A	Balancing Authority
Internal Representation	**Transmission Flow Modeling in ProbA Model**	Transportation/Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	Transfer Analysis Import/Export Limit for each Local Resource Zone	Transportation/ Pipeline	N/A	Transportation/Pipe and Bubble; Transmission Limits modeled between nodes	N/A	Transportation/Pipeline
Internal Representation	**Transmission Limit Ratings**	NY and Maritimes - short-term emergency; all other – normal	Short-term Emergency	normal and short-term emergency ratings	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
Internal Representation	**Transmission Uncertainty**	Selected Lines	No	No	No	No	N/A	No	N/A	No
External	**# Connected Areas**	3	4	4	7	1	3	5	3	0

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		NPCC	PJM	SERC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
	# External Areas in Study	8	4	4	7	1	0	0	SPP; MISO LRZ 8,9,10; Mexico	0
	Total External Nodes	8	59	4	1	1	N/A	N/A	3	0
	Modeling	Detailed	Detailed and At planning reserve margin	Detailed	Less Detailed	Detailed at their Planning Reserve Margin	N/A	No external assistance above firm contracts and transmission service reservation	Detailed at their Planning Reserve Margin	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	Not Considered	Yes	Yes	Yes, regulation, spin and non-spin reserve requirements modeled. Firm load shed to maintain 1150 MW of operating reserves.	No
Operating Procedures (pre-LOL)	**Forgo Operating Reserve**	OR to 0 in all Areas except Québec and New England.	Fully	Partially or Fully, depending on input from Assessment Area	N/A	N/A	Fully	Fully	Partially	Fully
	Other	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	CPP; DCLM;	None	None	Demand Response, Emergency	None	DR and Emergency Thermal Generation from Conventional Generators	None

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Commented [JS133]: From David Jacobson:
"I believe that "# connected areas" includes both internal and external areas or maybe just internal areas– should be clarified. Is WECC really 0?"

Commented [JS134R133]: The table has the connected areas in the "External" section. These are external areas. WECC currently has zero external connections physically, and models the zero external connections in their assessments.

Appendix D: ProbA Data Forms

The forms used for the 2020 Probabilistic Assessment can be found on the NERC PAWG webpage, located at the following link:
https://www.nerc.com/comm/PC/Pages/Probabilistic-Assessment-Working-Group-(PAWG).aspx

Appendix E – Additional Assessments by Regions or Assessment Areas

This informational Appendix serves as a list of references for more detailed information on assessments or assessment methods used by Regional Entities or Assessment Areas.

NERC Webpage:
www.nerc.com
The NERC webpage contains valuable information regarding its mission. For information on its assessments, please see the Reliability Assessment and Performance Analysis page. It also contains valuable information regarding the statistics for assessing BES reliability.

NPCC:
https://www.npcc.org/content/docs/public/library/resource-adequacy/2020/2020-12-01-nerc-ras-probabilistic-assessment-npcc-region.pdf
NPCC publishes a report that contains a more detailed look at the multi-area probabilistic reliability assessment for the NPCC Region, ~~used to fuel~~referenced in the NERC Probabilistic Assessment and this year's regional risk scenario~~s~~.

SERC:
serc1.org.
SERC publishes many different assessments that can be found in the link to their main webpage above. Please use the contact information in Appendix A for any questions.

WECC:
WECC's WARA Part 1.
WECC performed a separate assessment that contains more details on how the possible coal retirements in their region were selected and can affect their system's reliability.

WECC is also working on developing a portion of their webpage to provide educational materials on how they perform their probabilistic assessments and will work as a great educational material upon its completion.

MISO:
https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf
MISO performs a Loss of Load Expectation study on an annual basis as part of their Resource Adequacy construct.

PAWG Data Collections Technical Reference Document

Action
Approve

Summary
The NERC PAWG has responded to the RSTC and RAS comments on this study report. It combines all of the Assessment Areas' sensitivity results from the 2020 Probabilistic Assessment data and compares the results against the base case data. The NERC PAWG has obtained RAS approval and is seeking RSTC approval.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Data Collection

Approaches for Probabilistic Assessments
Technical Reference Document

June 2021

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Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

This document identifies and considers general categories of data inputs commonly used in loss-of-load probabilistic assessments across industry. These include data considerations with focus on parameters and collection methods for demand, thermal resources, energy-limited resources, emergency operating procedures (EOPs), and transmission representation. Entities must consider procuring or obtaining enough data to accurately represent the model parameters or inputs to effectively develop and run a probabilistic reliability study[1]. An entity wishing to conduct a probabilistic study should thoroughly review these data inputs and assumptions, the technical nature, and aspects of the model inputs in study, and the soundness of the results with all stakeholders as a standard operating practice. This document separates each of the identified major categories in a resource adequacy study and highlights the types of data, possible sources for the data, and other qualifiers associated with the inclusion of such information in a probabilistic study.

Key Points and Possible Future Work

The Probabilistic Assessment Working Group (PAWG) identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- An in-depth understanding of operational characteristics of the resources represented in a study is needed to determine the requested data points in order to study the resource.
    - Resource performance during ambient conditions (e.g., cold-weather or hot-weather performance) is of particular concern. Resource performance should be consistent with the weather –related conditions assumed in the case under study.
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This dependency between quantity of data needed for the transmission elements is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Battery energy storage systems (BESSs) can be modeled similarly to other energy-limited resources such as pumped hydro, with an emphasis on understanding the operational characteristics of the BESS.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

The PAWG also highlighted the following objectives for possible future ERO work to be further explored and addressed as needed:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting data, the thermal resources future outage rate may not be adequately represented by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions. Some entities do not have access to data sets to feed their models, and the need for more accurate studies

[1] In terms of reporting results and the metrics associated with probabilistic studies, the PAWG has published a separate document here.

may require access to data outside of those publicly available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.

- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Introduction

Today's electricity industry is under a period of significant transition. NERC and the ERO note several high-level trends that have affected the North American Bulk Power System's (BPS) planning and operations, such as the continued retirements of traditional baseload resources accompanied with the proliferation of renewable and other forms of variable generation. These trends have highlighted an increasing need for the industry to properly model, study, and plan for the future state and reliability of the grid. NERC and the ERO recognize that these trends are highly variable and carry increasing uncertainties, which further emphasize the need to enhance the traditional and deterministic forms of resource adequacy and reliability assessments. As was identified in the 2019 NERC Long Term Reliability Assessment (LTRA)[2] and the 2019 NERC State of Reliability report (SOR)[3], NERC looks to enhance its resource and transmission adequacy assessments by incorporating more probabilistic approaches in carrying out its mission of a highly secure and reliable BPS. To further that result, NERC continues to promote the use of more probabilistic approaches into reliability assessments providing further insights into assessing the adequacy and reliability of the BPS.

The NERC Probabilistic Assessment Working Group (PAWG) was tasked to explore and highlight the current data collection processes across the industry that are used to produce loss-of-load probabilistic studies that assess emerging reliability risks. This document explores and identifies requirements, sources, and techniques for obtaining and modeling data for possible usage in conducting probabilistic assessments. The objective of this document is to discuss and raise awareness of probabilistic methods and techniques available to assist entities in conducting reliability assessments of systems with resources of increasing performance uncertainties. This document supports the group's mission to promote the usage of probabilistic techniques and studies in carrying out NERC's mission.

While NERC has historically assessed resource adequacy using deterministic planning reserve margins, the purpose of this document is to discuss data collection considerations for a probabilistic assessment. The intended audience is the industry at large with the objective of raising the collective awareness of available data collection methods. This report is written as a reference document for industry participants to understand the options available for these data sources and to highlight any benefits or considerations that methods require.

In spring 2017, the PAWG conducted a survey of Registered Entities to better understand their assessment capabilities and identified challenges as they relate to probabilistic resource adequacy assessments. One of the recurring themes of survey responses was the challenges with selecting and managing large sums of data in order to develop realistic inputs to probabilistic models. The 2019 LTRA Key Findings indicate that future probabilistic assessments should incorporate the increasing uncertainty of resources and demand while also considering the increasing amounts or sources of data. The PAWG has developed this document to further assist entities wishing to or whom are actively engaged in conducting probabilistic assessments. The PAWG welcomes and invites subject matter experts' discussion and comments to this document to further develop widespread industry participant knowledge, application and acceptance of probabilistic studies and methodologies to assist in meeting the challenges posed to the electricity sector. This document is intended to complement ongoing industry work as there may be other groups that rest outside of NERC that are engaged in data collection discussions and probabilistic approach developments. As technical discussions and methods evolve further, the PAWG will update this document to meet industry needs.

There are numerous public and private sources of data that entities such as Planning Coordinators or Transmission Planners (TP) can use to develop a probabilistic study. NERC plays a valuable role in providing some of these sources via the NERC Generating Availability Data System (GADS) and Transmission Availability Data System (TADS); however, these are not the sole sources of data for a probabilistic study nor are they sufficient for every probabilistic reliability

[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf
[3] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

study. Many NERC Regional and Registered Entities utilize different models for their probabilistic reliability studies and this document attempts to summarize the collective approach and basic data needed to perform this work. Depending on the tools available to the entity, additional data from other sources may be required as the models available to that platform may require more information than the data source collects.

Chapter 1: Demand

Demand modeling in a probabilistic resource adequacy study is typically conducted through a combination of several inputs, including the utilization of historical data, demand forecasts, uncertainties, and assumptions specific to the system under study. Demand or load shapes can be modelled based on historical monthly or hourly peak demand profiles and shapes, scaled to reflect forecasted conditions. In many cases in this chapter, the word "demand" and "load" may be used to reflect the modeling of end use customer MW draw. In the case of "demand", the emphasis is on the MW amount and its time distribution, while the term "load" can encompass other complexities outside of "demand," which may indirectly capture demand acting as a resource to offset the electrical system's draw at that time. Some models may not have the complexity to identify the nuances between the two terms, or some definitions may not be as clear as the above distinction. However, in terms of the data, most of the sources and procedures will not vary between "demand" or "load" and the terms can be used in the following chapter interchangeably.

Demand Considerations

In a probabilistic resource adequacy study, accounting for specific assumptions regarding the amount and uncertainty of demand plays a significant impact on probabilistic indices results. Entities should consider the use of multiple demand level scenarios in assessing the resource adequacy of their systems under study. An example of these demand levels could be specific forecasts, such as 50/50 or 90/10 system forecasts that represent the probabilities of exceeding explicit levels. Different techniques can also be employed using statistical calculations, such as probability-weighted averaging. Probability-weighted averages calculate load level indices with corresponding probabilities of occurrence, thus representing the uncertainty in system demand due to external inputs, such as weather and economic factors. An example of this could be by using distributions of monthly peak demands versus the annual system peak demands. The selection and usage of multiple load levels can assist entities in planning against uncertainties, such as the occurrence of more extreme demand conditions or extended stressed system conditions. To gather some of these selections, a demand curve can be developed. To build demand curves, the RTO/ISO can utilize their metered data, as the granular data provides an easy way to sample the demand.

Demand Curve Selection

Demand can follow many different socio-economic causes that would shift the shape of the demand curve in a multitude of ways; however, weather or climate is commonly identified as a primary driver of demand impacts. To help mitigate this, the demand curve should be constructed by considering the impact of differing weather conditions to better capture temperature sensitivity. Some of the considerations for selection can include ambient temperature for seasonal conditions, wind speed, and precipitation. Each of these meteorological markers has demonstrated impact onto the demand curve and should be considered when gathering data surrounding demand during those time periods. Specifically related to the curve construction, the peak, nadir, and ramping rates have substantial influence on the reliability impacts to the system in study[4]. Accurate characterization for those periods is important for the planning and scheduling of generation and ancillary resources during the study.

Because the resource planner desires to capture a full distribution of possible demand conditions, the demand curve selection is important when collecting a proper sample of data. These conditions include cool, average, hot, and extremely hot summers; warm, average, cold, and extremely cold winters; and low, average, and high meteorological conditions such as irradiance or wind speed. These will emphasize some of the peaks, nadirs, and ramping rates. Accurate characterization of the identified risk depends on the samples taken and the selection of the curves those samples produce. For instance, if the demand data collected contains 25 years of curves selecting those curves that accentuate the peaks, nadirs, and ramping rates will allow the resource planner to more accurately capture the

[4] Historically, the planning process typically accentuated peak conditions. As risk moves away from the on-peak periods (over a season or a day), looking at curves that accentuate other aspects of the demand curve is warranted.

anticipated risk conditions of the peaks, nadirs, and ramping rates. In the same light, selecting all the curves will weight all years as equally probable.

Load Scenarios

Loading level directly determines the required amount of resources in the study due to the load and generation balance. In addition, the load level and composition play a significant influence on the system in study. When performing a resource adequacy study, a TP/PC must select the appropriate scenarios that either stress or relate demand to differing extreme conditions. In order to do this, planners will need to gather demand data associated with the weather conditions specified above. More specifically, this will be a distribution of load scenarios across demand curves. One example distribution is cool, average, hot, and extremely hot summers along with warm, average, cold, and extremely cold winters. Couple those scenarios with high, average, and low wind speeds as well as high, average, and low precipitation (or water flows) and a diverse amount of scenarios are available for selection in the study. As many of these scenarios are study dependent, the specific study scope can assist in either paring this list down or adding to it. Additionally, sensitivities can also accentuate specific loads and can assist the planner in studying the impact to their system. For example, a load scenario that assumes very aggressive electrification of the transportation system will accentuate the usage of demand during the hours in use, as well as on the days of the week that transportation is more heavily used.

Load Forecast Uncertainty (LFU) Considerations

Realized load can differ from projected load for multiple reasons. First, because weather cannot be exactly predicted and will cause peak load to differ from the normalized-weather forecast (as discussed in the weather-related LFU section). Second, because there are uncertainties in population growth, economic growth, energy efficiency adoption rates, and other factors. Data for these topics can be regulatory based and would vary by jurisdiction and program. These non-weather drivers of load forecast uncertainties (LFUs) differ from weather related LFUs because they increase with the forward planning period, while weather uncertainties will generally remain constant and be independent from the period being studied.

Non-Weather Related LFU

From the above, the uncertainties in population growth and the associated demand forecast can be addressed by a statistical approach at quantifying the uncertainty. To best illustrate this, consider this example. For each weather-year load forecast, five non-weather load forecast uncertainty multipliers are applied to all load hours. **Figure 1.1** shows the uncertainty as a percentage of the 50th percentile (P50 or "50/50") peak load forecast, indicating that the forecast uncertainty increases as one moves further into the future. Each multiplier is assigned an associated normal-curve-based probability with the sum of the probabilities totaling 100 percent. **Figure 1.2** shows the three-year forward load forecast uncertainty multipliers[5]. To calculate the weighted-average results across all load scenarios, the weather-year probability weights and the non-weather probability weights are multiplied to create joint probability weights. More details about non-weather load forecast uncertainty can be found in other reports in the industry[6].

[5] While the figure shows symmetric forward LFE, these points may not be symmetric.

[6] A few relevant reports are posted on the Electric Reliability Council of Texas (ERCOT) website, which contains material listed here: http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf; http://www.ercot.com/content/wcm/lists/167026/2018_12_20_ERCOT_MERM_Report_Final.pdf; http://www.ercot.com/content/wcm/lists/114801/ERCOT_Study_Process_and_Methodology_Manual_for_EORM-MERM_12-12-2017_v1.0.docx

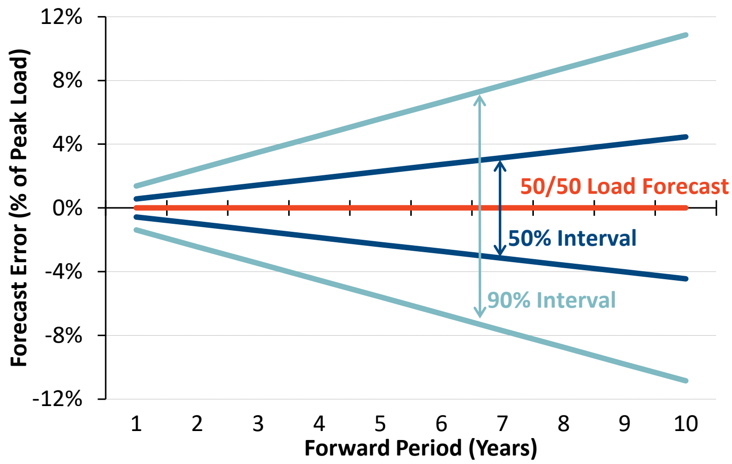

Figure 1.1: Non-Weather Forecast Uncertainty with Increasing Forward Period

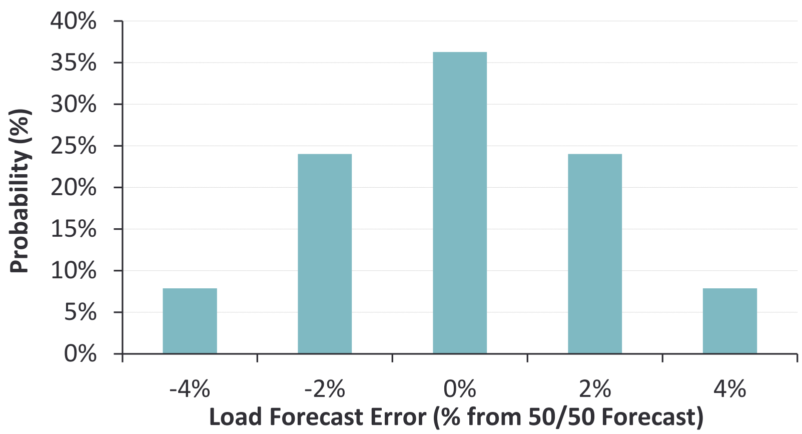

Figure 1.2: Three-Year Forward LFE with Discrete Error Points Modeled

Weather-Related LFU

While LFU methods have the ability to capture many uncertainties related to the load, weather factors are a significant driver of load and their uncertainties can be captured when undertaking a probabilistic assessment. The weather-related methods described below can be utilized to capture the uncertainty with respect to year-over-year differences. Typically, weather-related LFU captures the variance of conditions documented in the historic conditions. If the study desires to simulate extreme conditions outside of what historic conditions can predict (e.g., sustained higher than record wind speeds) the resource planner will need to adjust or produce data that captures those conditions[7].

Some data points to consider are ambient temperature, dew point, wind speed, and cloud cover across a variety of stations in the geographic region associated with the assessment area. These variables have been determined to relate to the variance in load, and one of the sources of data on those variables is from weather stations. To provide enough accuracy to depict the weather-related LFU, multiple years of weather are required to capture this uncertainty. The Independent Electricity System Operator (IESO) currently uses 31 weather years and runs the load model forecast on those years shifted up to seven days to account for each numeric day falling on a given day of the

[7] Note that this type of adjustment would need to be study-wide in order to have consistent study conditions for these extreme weather scenarios. This does not; however, adjust the data collection technique for weather-related LFU.

week. That is, day 100 will lie on a Monday, Tuesday, Wednesday, Thursday, Friday, Saturday, and Sunday to account for differences the load has based on temporal shifts. This equates to 465 distinct weather simulations[8] and from there, the Load Forecast Uncertainty could be determined. Other entities, such as Argonne National Labs, have taken the information at weather stations and numerical weather prediction (NWP) data coupling to determine the weather-related LFU.

SERC gathers this weather information from FERC Form 714 Part 3, Schedule 2[9]. This source is by no means the only resource for weather-related uncertainty, as there does exist data through metering at the ISO/RTO level. The ISO/RTO granular data opens up more ways to construct the LFU, similar to the benefits in the demand section above. The FERC data source requires that the Electric Utility Planning Area provide hourly demand levels in megawatts and the source starts at year 1993 for some regions. The format changes based on the year as per Table 1.1.

Table 1.1: FERC Data Source Format

Reporting Year	File Format	Notes on Use
1993 to 2004	.zip files organized by reporting year and NERC regions (legacy and current). Microsoft Windows compatible programs to read spreadsheet and text files, there exists a file that needs conversion in the archive, but many programs exist to convert to Microsoft products. Each entity has a separate format for each	Ensure that the data conversion you use for .wk1 files can be converted to Microsoft Excel. No viewer exists and must download to view the data. Conversions for analysis regarding multiple entities are needed to ensure the data gathered is uniform in the study.
2005	Similar to 1993 to 2004	Individual Entity filings can be viewed through the FERC eLibrary
2006 to present	All responding entities have the data and have the .zip archive to download. That archive contains .csv file formats	FERC Form Viewer is able to fully visualize the data prior to download. This year a unified format is applied across entities

It is suggested that the data be converted to a daily hour ending (1-24) matrix format. In order to perform that conversion, a few cleansing techniques can be utilized. Associated hourly trends and other whole filling algorithms will help to complete the database when holes or incompatible formats occur when adjusting time zones. To assist, FERC has placed a relational database viewer to assist with the collection of this data. See **Figure 1.3** for the database schema provided. Additional screening approaches to detect anomalies with the data that include outlier detection are also needed to ensure a good quality data set prior to utilization in the study.

[8] Seven days forward, seven days backward, and the day that the historic measurement was taken multiplied by the number of years. For 31 weather years, this is (7+7+1)*31 = 465.
[9] https://www.ferc.gov/docs-filing/forms/form-714/data.asp?csrt=18240670882965036364

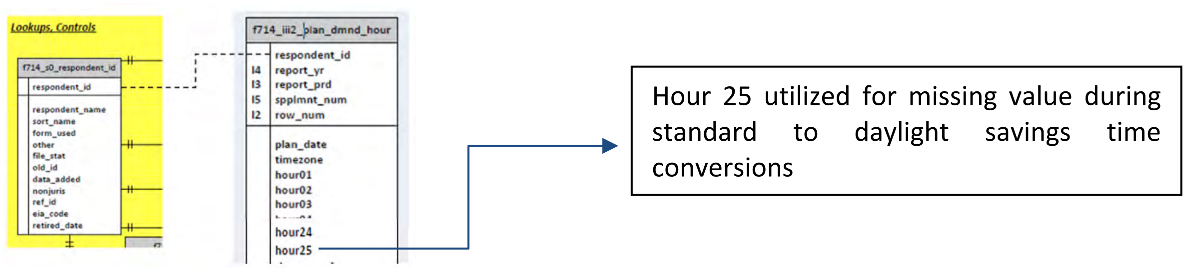

Figure 1.3: FERC Database Schema

In addition to just these hole filling requirements and other changes as required for outlier detection, additional screening approaches are needed to reconstruct the data relationships. An example of what SERC has done to additionally adjust the FERC database forms can be found in **Figure 1.4**. As shown, the additional approaches can impose a slight difference between the NERC Long Term Reliability Assessment (LTRA) data and what is filed in the FERC database. For probabilistic studies, it is best to use the data in the LTRA (i.e., post additional screening) in order to calculate the weather-related LFU.

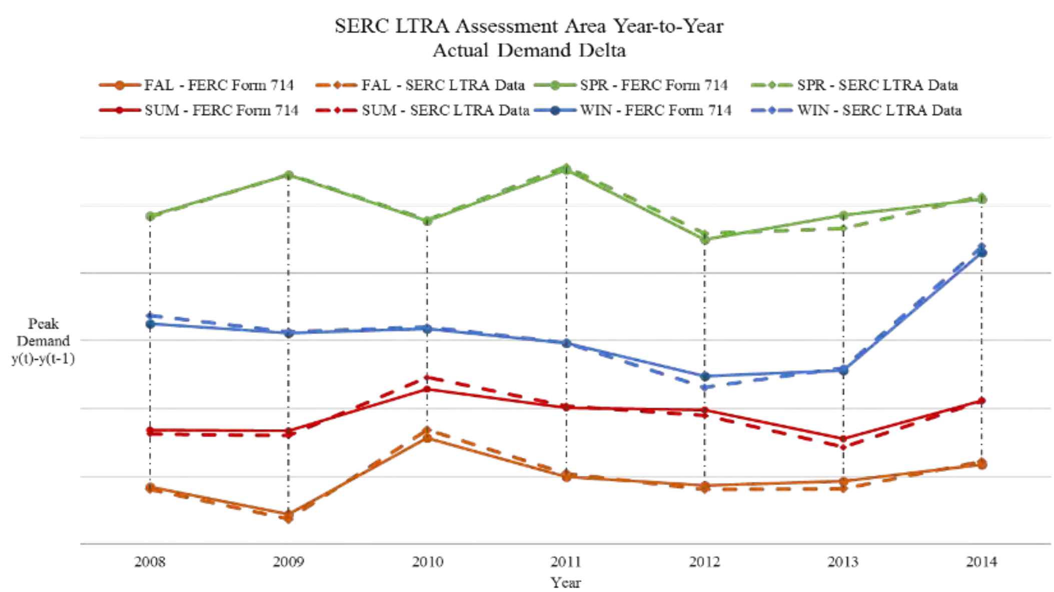

Figure 1.4: SERC Adjustment Example Utilizing FERC Databases

Complexities in Modeling Demand

While the basics of demand modeling in probabilistic studies is detailed above, multiple issues arise when allocating operational characteristics and other contractual obligations into the probabilistic study. Some of these complexities arise especially during the NERC Probabilistic Assessment process and are reflected in the following sections.

Modeling Multi-Area Systems

Entities should consider the correlation of peak demands with neighboring area systems in developing composite load shapes. These periods, perhaps due to heightened weather or economic conditions, represent high degrees of peak load correlations and represent the highest amount of coincident demands. The highest coincident peak demands represent a conservative assumption in the ability of the overall system to meet demand by reducing the ability or reliance of neighboring systems assistance in meeting peak loads. To capture this in the probabilistic study, load shapes from different Assessment Areas' geographic boundaries should have the same time frame as the study. Sometimes these regions change their boundaries; however, the goal is to stay consistent across the study in terms of data quality feeding the different geographic regions in the study. In cases where the boundaries of the probabilistic study cross different Assessment Area's geographic regions, data should be coordinated to capture the system coincident peak as a composite of the many geographic regions in the study.

Demand Response (DR)

For the probabilistic incorporation of demand response, the particular mechanics of each program or structure will dictate the utilization of the demand response. Primarily of concern is the amount of load relief the demand response provides at every stage, the number of times the resource can be called in a given period, and any other limitations on the duration or amount of relief the response[10]. For regions where this is required to be registered, the above information can be found on the registration forms; however, not all regions are able to provide those registration forms. In these areas, the program can define many of the parameters; however, historical usage information can solidify the amount of load relief at each demand response tier. This historical usage however may be affected by more parameters than just the load relief as certain connections or disconnections affect the availability of the demand response to achieve the load relief. As these are quite complex, the PAWG recommends using a data source that captures operational conditions surrounding demand response in order to capture any cross correlations, or to calculate them otherwise.

For demand response that is registered, the amount of relief, number of times it can be called, and other duration limitations or restrictions are found in that registration forms to enter into their respective databases. For unregistered resources, resource planners are encouraged to use methods to predict their availability by analysis of past performance and heuristics going into the future to obtain these values. A quick overview of the data inputs for demand response are summarized in **Table 1.2**.

Table 1.2: Information Required for Demand Response (DR)

Information Required	Example Collection Source
Amount of load relief	Registration database that aggregates the load relief or informal survey to non-registered devices
Number of times in a given time period demand response can be called	State/Provincial level orders or similar utility contracts regarding Demand Response
Duration limitations	State/Provincial level orders or similar utility contracts regarding Demand Response
Tiers of response	State/Provincial level orders or similar utility contracts regarding Demand Response
Other restrictions	Utility specific directives, databases on controllable loads

In addition, there are market structures that contain different levels of this type of demand response. These are sometimes labeled as Emergency Response Service (ERS), but these are going to be varying by when they can be called and the response of the service. Supplemental collection of similar sources[11] should be utilized to capture these tiers of response.

[10] For example, one of the more difficult considerations in Demand Response is the expected performance versus actual performance during extreme temperatures.

[11] State or other regulatory bodies as well as other internal sources may manage these sources.

Demand and Demand Response as a Resource

When demand response is modeled in the demand profiles themselves, adjustments to the demand profile will apply to the demand response. Conversely, when demand response is modeled as a resource, it is not included in the demand profiles and is not included in any of the alterations in the demand section. To further clarify the difference, when DR is modeled as a resource, adjustments from the weather or non-weather related LFU will be only on demand rather than both the DR and the demand. This can then be directly used in the study as all of the adjustments are on demand curve. When modeling DR as a resource, these techniques need to also be applied to the demand response modeled as a resource as such LFUs will impact the key model parameters in **Table 1.2**. The data source chosen to provide the LFU should be flexible to adjust for either modeling scenario. The key point for this separation is to ensure any adjustments to demand are adjusting the operational characteristic of the demand response or the demand, rather than both. If separating the demand response as a separate resource, then the collection of data may require more data than just the amount of load relief at any given time in the simulation and may require time-of-use or other operational profiles to determine in-simulation output of the demand response when called upon.

Distributed Energy Resources (DER)

DERs can be a multitude of differing resource types connected through the distribution system; however, many of the current installations are photovoltaic solar (Solar PV). Some probabilistic studies utilize simulated profiles as a load modifier in performing the load forecasts. In some areas, a DER forecast may be available, but these forecasts are generally at the state regulation level. As such, the forecasts may vary between Assessment Areas, and could even vary internally to the Assessment area if such boundaries cross state lines. Such data can be valuable to the planner when performing the probabilistic assessments, but care needs to be taken such that the DER are not double counted in the demand portion of the study. That is, if a load modifier for simulated profiles is used; additional forecasts should not double count this modifier. See the section on Generation Availability in Behind the Meter Generation (found in Chapter 2) to see the setup for modeling DER as an explicit stochastic resource. The difference with current DER technology, however, is the high correlation to irradiance for their availability. With this high correlation, weather-related data as demonstrated above could supply another marker into the DER's availability. These types of resources use a mix of demand techniques as seen above and parameters seen in Chapter 2, and as such similar data sources can be expected when modeling the DER in a probabilistic study. As there is no current database or source for availability of DER, a mix of operational data and weather data can be expected to model each state of the stochastic representation.

Data Validation & Cleansing

Once data are formatted across all reporting years, entities should consider performing data reviews and validations, as well as post-processing work if the data are large to ensure the underlying data in question is of sound quality. These validation and cleansing methods are not just relegated to demand data, and are summarized generally in Appendix A.

Demand Reconstruction under Boundary Changes

FERC 714 filings are housed in a central resource so an entity can import the same submitted demand data into the resource adequacy study. This, however, imposes an issue where an entity's boundary changes or is under study in a different boundary. These geographic changes will require some reconstruction of the demand in each area in order to maintain the same level of demand uncertainty across the entire study region. Two options generally exist, a time-series reconstruction or a comparison of the peak demand in each area creating a ratio. The former is more time intensive but provides a greater level of accuracy for the added or reduced demand based on the geographic change. The latter option provides a quicker way to adjust the demand shape in the study but assumes that the peak ratio is valid for all times in the year. This creates a less accurate depiction of the demand change.

Demand Data Requirements

The data requirements for use in resource adequacy studies revolve generally around the time granularity of the data. An hourly representation of demand levels is required for most studies, and associated databases may or may not have such hourly representations. In such instances, hole filling programs and other trend-based algorithms can fill the gaps associated with transferring the data into hourly format. This is crucial as some of the current metrics the PAWG has in their previous reports, the metrics are in hourly format. The reader is reminded that many databases may not have the greatest quality of data; however, such data could be sufficient for their report or study. Such databases simply require the post processing methodologies as discussed in the SERC example in **Figure 1.4**.

Collection methods

There are varieties of both sources and mechanisms for which data can be acquired and utilized for conducting probabilistic assessments. The specific data needed can vary significantly depending on the type of assessment as well as the underlying characteristics of the system under study. Aspects potentially affecting the availability of data include status of local, state, federal regulatory framework, market construct and available operational data, underlying resource mix and trends information, and/or agreements or tariffs with other Registered Entities. For NERC Registered Entities conducting probabilistic assessments, data sources being utilized vary by jurisdiction and applicability to their respective systems. A summary table of the various types of collection sources for different types of entities is found in **Table 1.3**. It is anticipated that other data sources exist for this data, and the table is provided as a start for collecting the type of data.

Table 1.3: Data Collection Notes on Different Entities

Entity Category	Entity	Notes on Data Available
Federal, State, or Provincial level	US Energy Information Administration (EIA)	The EIA contains a lot of valuable information on various energy products, including: LNG export, generation capacity, and an hourly grid monitor. Care must be taken to gather the source of data, or to understand the assumptions associated with the reported charts, graphs, or other tools.
	National Renewable Energy Laboratory (NREL)	The data available contains maps, models, and tools used for energy analysis. Specific ones help with association of data and others are tools to feed probabilistic studies, such as weather data.
	US Census Bureau for US based regions and Statistics Canada for Canadian regions	The data here contain population and census data in particular geographic regions. Additionally, collects and publishes nationally commissioned data on such populations.
	Public Utilities Commissions	These entities can provide state, provincial, or local agency data specific to energy and resource type.
NERC Registered	Generator Owners or Generator Operators (GOs/GOPs)	Generation entities can report their outage information to the NERC GADS, and in cases where more information is required, can assist in determining their generation availability. The latter is especially true for newer plants.
	Distribution Providers (DPs)	These entities provide their distribution system to serve end-use customers. These entities are able to provide information on their served demand

Table 1.3: Data Collection Notes on Different Entities		
Entity Category	**Entity**	**Notes on Data Available**
	Transmission Owners (TOs)	These entities are the owners of equipment for the long distance transmission of power and may be able to provide outage information related to the equipment they own. For example: transmission lines and transformers
Operations/Market	ISO/RTO Capacity Markets	Each ISO/RTO provides an outlook on the anticipated socio-economic changes and some of them provide outputs usable in probabilistic studies

Chapter 2: Thermal Resources

A large majority of resources in the BPS are thermal resources that convert chemical energy into electrical energy by burning of a fuel. These resources can vary dramatically in construction; however, the focus on data collection for reliability studies is on modeling the availability of the generation and the assumed operating level of that generation. In general, a two state Markov model is the end goal for these types of resources so data collection will center on gathering enough information to fill the model. As other models exist, this section will detail the many sources of filling out any type of stochastic model.

Outage Data

Outages must be considered for all resources in conducting probabilistic assessments as outages have the ability to materially affect the availability of generators to meet the demand. NERC Registered Entities typically utilize a combination of data sources[12] to account for planned and unplanned outages along with their associated uncertainties. These typically include a combination of historical information, performance, and potential correlations to weather data. Some of the types of forms used for the information include generator availability[13] and outage rates (NERC GADS), such as the equivalent forced outage rate, FERC 714 hourly reported data, and market data. In addition, some selected entities utilize a combination of forecasted resource price data, powerflow studies or perform regression analyses for potential correlations with outside datasets.

> **Key Takeaway:**
> Building the outage rates of thermal resources requires forced, planned, maintenance, and other outage types. A single data source may not have all the types of outages.

For thermal resources, the majority of the outage data required to formulate the equivalent forced outage rate will require a data source including parameters for planned outages, maintenance frequency and length, and forced outages, which include repair and failure rates[14]. The parameters associated with the planned outages include the maintenance cycle and length, usually related to the months of the year (i.e., two of the twelve months) and the length of days associated with that outage. There does exist cases where the planned outages can have durations across years, and such cases will need to assure that the durations are related to yearly outage metrics. In addition to these planned outage inputs, the parameters associated with the forced outages include full outage mean time to repair, full outage mean time to failure, and partial outage deratings for however many derate states there are. For partial outages, the critical component is hours for MW unavailable, no matter the derate type. The sum of the zone is the critical component, then grouping by event type, can be informative for other model or data validation considerations.

The data source for the forced outage rates can be fulfilled in the NERC GADS database; however, that data does not include reported planned outages and is a calendar-reporting database where multi-year events may have differing unique identifiers. To account for those differences, supplemental information is required to bridge the gaps. In an informal poll by PAWG membership at their meetings, many of the companies contain an internal data source that accounts for the planned outage data. Some of these functions are not in the planning departments, but rather in the operational departments. When using operational tools, it is important to remember that the data may need to be altered in order to account for errors incurred while logging the planned maintenance records. Additionally, a

[12] These data sources may be quite large. For instance, ANL has over 650 million records of customer outage data sampled at about every 15 minutes.

[13] Depending on the generation model, EFOR versus EFORd will demonstrate if the plant was in demand when the outage occurred for use in determining the generation availability. The NERC Performance Analysis Subcommittee has identified that the NERC GADS does not have enough information to calculate the EFORd modeled outages using that data source only. As such, the resource planner needs additional operational data if using this in the model.

[14] These sources for data are used to develop an estimate for the FOR of the unit. IEEE Std. 859-2018 describes the statistical modeling concerns surrounding the use of point estimates or averaging of results as well as the assumption of independent outages across the generation fleet.

Canadian Electrical Association (CEA) reliability database can also provide the statistics regarding thermal outages that aren't related to event-based performance sources, much like the NERC GADS. In each of these sources, cleansing of the data in order to align the information submitted to the database and aligning it with the records found in operations that take on these derates. This type of cleansing may require knowledge of the model[15] in order to align the transition rates with the submitted and forced conditions.

When utilizing the NERC GADS database, a few other peculiarities exist for thermal units, as the reporting for units may not be consistent across the database. For units with a high startup rate, taking startup outage out of EFOR is a more appropriate way to model the stochastic nature of the unit. Then the resource planner can utilize that reduced EFOR for those units. The startup failure rate may show up as a derate or as an outage rate. An additional consideration exists for NERC GADS. The database is set up for the immediate timeframe, meaning that using it as a data source for derates will only provide the reduction of MW from the current ambient conditions. For some thermal units, this is not an adequate indication of the starting point, as some units are highly sensitive to ambient temperature. For these units, additional data in the form of a temperature curve assists in developing their stochastic model.

For entities that do not use the GADS data, such as the IESO, they have an internal database that considers all outages (submitted, forced, and approved) on a per generator basis. Other entities also maintain an internal central database for this data. Generally, those entities utilize a set of samples from historical databases and submit planned outages to forecast the generators outage data for the study. This outage data is similar to the planned outage databases discussed above. Similar conditions exist to ensure data accuracy with reporting of planned outages in this type of system as well as the forced outage data. For the IESO, the planned outages are modeled as a part of future planned outages, 10 Year Forms with projected outage schedules, and historical planned outage rates. By collecting the data in one source, IESO is able to model their thermal resources.

Perspectives on Predictive Outage Forecasting

Key Takeaway:
Predictive Outage schedulers provide methods to forecast outages in future years, where the planner conducts the probabilistic resource adequacy study.

Historical Generation Availability Data System (GADS) data collected by NERC is a common and standard data source for entities modeling conventional generation[16]. Operational schedulers can also be a source of this information, and the Control Room Operations Window (CROW) would be another valid data source for predictive outage forecasting. However, access to the information within this database can be challenging and unit specific information is not accessible to all entities[17] . An alternative way to obtain the data is by requesting it from resource entities directly. A specific example for requesting GADS data from resource entities, including the data request notice and data submission form, can be found in Appendix B. Since conventional generation outage trends may change over time, it is useful to predict outages in planning studies. An example of such is in ERCOT, where staff reviewed several predictive algorithms, such as the Prophet[18] tool developed by Facebook, to determine its usefulness in capturing changing trends. A predictive forecast approach based on Prophet[19] has been tested to forecast fleet-wide forced outages. For unit-specific outages used in probabilistic studies, the predictive approach may not be applicable. Based on the ERCOT's experiences with such data sources, the predictive approaches can help visualize the nature of the combined historical and planned outages to provide a way to more accurately collect the correct outage rates to apply to the study. To fuel a stochastic model, these predictive outage-forecasting tools should include mean time to failure, mean time to repair, mean time between failures, and other transitions between the stochastic states to be an effective data source.

[15] Such as the distinction between two-state and multi-state Markov models for thermal resources

[16] These databases log historic outage data to calculate their availability. There are conversations on the use or nonuse of historic data in predictive probabilistic studies found in IEEE Std. 762-2018 and IEEE Std. 859-2018.

[17] Only entities authorized to view unit specific data are allowed access to that data due to the sensitivities surrounding the data.

[18] A link to the tool can be found here

[19] Link for the Prophet tool can be found here

Data Considerations for Capacity Constraints

> **Key Takeaway:**
> Many of the capacity modifications are highly model dependent, indicating the need for varying data source requirements. Data collection should be considered on a case-by-case basis.

Outside of planned and forced generator outages, there are other factors that can also affect supply availability, which must be accounted for in reliability assessments. Factors such as emissions constraints, unit deratings, fuel availability and capacity constraints all limit the availability and ability for supply side resources to meet the demand and can have wide implications for reliability, especially in extenuating weather or stressed system conditions. Additionally, some future market conditions may impact the capacity or dispatch of a unit where such markets affect the operational characteristics of the thermal generation resource. Some of these constraints can be found in the source documents that dictate the market rules, or in the regulatory body that imposed the rules in the present or future market.

Emissions Constraints

Entities must account for the potential application of emissions if they plan to model these constraints in their resource adequacy studies. Some of these constraints are considered during economic dispatch of the units, while other models require explicit states modeled based upon the study conditions. Much of these constraints are regulated by different government agencies, and as such, they are generally unique in each area. In general, the assumption for emissions is that during blackout or resource inadequate periods the regulators will lift the constraint; however, these constraints can be adjusted by modeling the outage rates, capacity limits, and other water flow constraints in order to model the impact these policies have on specific generators. However, since the modeling varies, the amount of data required will vary as well. Resource planners are suggested to look to government agencies or emissions regulators in order to gather enough information to model the emissions constraints.

Fuel Availability Data

The NERC Electric-Gas Working Group (EGWG) has helped determine the interfaces and potential interdependencies that the electricity sector has with the gas pipelines and potential disruptions of those pipelines[20]. As it pertains to resource adequacy, the data required to model the impact of pipelines can be cumbersome and is not available in NERC GADS. The data source selected should consider mean time to failure and mean time to repair rates associated with those operating states. These general considerations are typically accounted for using Equivalent Forced Outage Duration (EFORd) in some regions, but others do not account for this in the EFORd as that measure is typically reserved for mechanical outages. Similarly, the fuel availability statistics will need to account for the derate associated with lack of fuel. Due to these complexities, capturing this in a probabilistic study is very cumbersome and will require more than usual amounts of data to perform a study. A resource planner will require access to pipeline outages and other gas information systems in order to model the impact on a resource adequacy study. In some very restrictive areas for fuel availability, a resource planner can consider modeling this thermal resource as an energy limited resource with considering some aspects of other energy limited resources in Chapter 3. In particular, the available natural gas, in MBTU[21] per day, from a data source in these scarce periods is important to consider.

[20] Link to EGWG report here

[21] This is a common measurement in the natural gas industry to indicate 1,000 British Thermal Units (BTUs)

Capacity Modification on Ambient Conditions

Key Takeaway:
Thermal power curves allow the study to adjust the capacity based on the ambient temperature studied. Modeling ambient conditions also requires weather data close to the resource

To capture the capacity modifications due to differing ambient temperatures, some entities send a survey to their Generator Owners with capacities at specific temperature points. These points provide a curve, and that particular curve is used to set the capacity derates under the ambient conditions; the source of those ambient temperatures is the same as the Weather-Related LFU portion discussed in Chapter 1. The combination of these two provides a simplified method to model correlations between the weather and generator outputs for the forecasted short-term; nevertheless, the source for these model considerations stays the same: a survey to generator owners to generate a thermal curve and the weather-related LFU sources.

Other capacity modifications depending on the ambient conditions exist. Terms like High Sustainability Limit, which ERCOT defined as the real time maximum sustained energy production of a resource; Dependable Maximum Net Capacity, which is defined as the maximum power a resource can supply under specific conditions for a given time interval without exceeding thermal or other stress violations; and Seasonal Capacity, which is the capacity of a resource in a given season, come into play. These terms all try to describe the energy restrictions on ambient conditions and constraints that would hinder the modeled generator in the reliability study from producing its nameplate value. Should this be a major concern in the study, the data source[22] chosen should be equipped to handle the desired study conditions and gather enough data on the constraint to model it stochastically. At minimum, this means determining the mean values for transitioning between the states.

Generation Availability in BTM Generation

Data sources for behind the meter generation will be highly model dependent, but there are a few considerations for these generators, which typically do not report in surveys or other generator data sources. These types of resources sometimes can be found as a load modifier, but those resources can sometimes be sensitive to a market price or other dispatch signals, and are thus not related to the electrical characteristics at their Point of Interconnection (POI). To gather enough data on these types of resources, a case-by-case data structure will most likely be needed or a wide swath of assumptions to be made based on the available data to the resource planner. Two approaches exist for these generators. One is to net them against the load to which they are close geographically, which carries all the assumptions of demand modeling. The other is to model these as discrete stochastic resources, with a recommendation for a simple two state Markov model that can be developed off operational data superimposed on other time-synchronized measurements to determine the resource's full capacity. If modeling via the latter method, the same data types outlined in this Chapter are expected to be placed into the model, and as such similar data are to be collected. Collecting this type of data may be cumbersome for these types of generators, so heuristics developed off knowledge of these facilities can aid in determining when to collect the data to best model the resource.

[22] This may be a survey to the GO, as the IESO example above demonstrates

Chapter 3: Energy Limited Resources

Some of the common resource adequacy discussions are based around a discussion on the capacity of resources and the availability of those resources to meet the level of demand in a study. In the case of energy limited resources, such as hydro, wind and solar, capacity related discussions are only one facet of reliability planning. This chapter focuses on the different types of energy limited resources to describe how to collect data representative of them for use in a probabilistic study.

Hydro Units

The vast majority of hydro generating facilities are considered as energy limited units since these facilities are dependent on the availability of water resource. The time constant for the availability of water may be longer than that of wind or solar. The effect of unit-forced unavailability is not significant on hydro generating system reliability; therefore, many resource planners incorporate this unavailability in estimates of energy limitations when conducting probabilistic analysis. Some of the input parameters for each hydro power plant are:

- Installed/in-service, Planned and retirement dates
- Monthly maximum and minimum output of each plant
- Monthly available energy from each plant
- Energy distribution (available energy to hydro unit)
- Forced Outage Rate (FOR) or EFORd

For hydro generating facilities, some entities may assume that the available water or fuel for each plant has little or no uncertainty, or that the water resource is in a drought condition. This is a conservative approach to ensure that sufficient resources will be available when needed. However, if the uncertainty is to be modeled, the data needed to incorporate that into the hydro facilities model requires similar data to other weather-related energy limited resources.

Simulated Solar Generation

In a loss-of-load probabilistic study, it is important to cover all of the weather years of data for resources highly correlated to weather data (e.g. Solar PV). In order to do so, resource planners can simulate the expected behavior of the solar plant for use in their loss-of-load probabilistic studies, and many tools are available to augment or replace observed historical generation data for a particular resource or neighboring resources. One such tool is the Weather Research and Forecasting (WRF) model[23] used to generate the historical atmospheric variables such as wind speed, temperature, and irradiance (as well as snow, ice, or other ground cover), which in turn simulate solar power production at each location in the model. The most important data points to produce a simulated solar profile are the types of arrays, soiling, shade, snow or ice cover, and control parameters associated with tracking the solar bodies. Some tools that utilize these parameters to then convert into AC capacity are the NREL SAM tool[24] with the former inputting parameters to produce the profile and the latter producing profiles off generic adjustments. The latter takes into account multi-order variables when producing the curves, but requires additional site-specific data that may not be available when conducting a resource adequacy study; however, it still remains an option for more specific profiles.

Key Takeaway:
Simulated profiles can be performed for both existing and planned solar PV sites. In either case, site-specific details help refine the fidelity of the profile. Some tools provide DC capacity and others AC capacity. For use in resource adequacy studies or assessments, an AC capacity will need to be calculated if the tool does not do so.

[23] Information on this model is available here
[24] Available here. See information on the PVWatts portion of the tool

To walk through the process, ERCOT computed the atmospheric values and adjusted them using surface station data and input them into a proprietary PV model to produce the hourly power output profiles. Programs mentioned above would also provide a profile, but ERCOT utilized proprietary models to accomplish the goal, yet another option available to resource planners. More details about developing hourly solar power profiles can be found in the solar profile methodology report, available on ERCOT's Resource Adequacy webpage[25].

If utilizing site-specific information to inform profiles, data found in **Table 3.1** is useful in providing to a program or vender when gathering simulated solar profiles. Some of the information is expected to be assumed, as some can be site-specific and many of those parameters are not available at the time of study.

Table 3.1: Solar Profile Data Requirements

Category	Data Point	What to Gather
Static Plant Details	Installed Plant Capacity	DC MW Capacity
	Tracking System Type	Fixed, Single, or Dual Axis
	Tracking Origination	Azimuth, north-south, other
	Module Tilt	Horizontal, Tilt to Latitude, other
	Module Azimuth	Degrees off Azimuth
	Ground Cover Ratio	Ratio of array coverage by other arrays
DC to AC Conversation	DC to AC Ratio	Efficiency of DC to AC conversion in MW
Inverter Details	Inverter Capacity	Either 1) Inverter make and model, or 2) Number of Inverters and the inverter capacity
PV Module Details	Module Capacity	Either 1) Module make and model, or 2) Number of Modules per string and the module capacity

Key Takeaway:
Public resources exist to generate the simulated solar profile; however, non-public options exist for use as well.

Site-specific parameters are not required for these profiles; however, they provide a more granular approach to modeling the contributions of solar resources. In general, the solar profile is a time series of data on the total power production (in MW) at a solar facility. Two methods exist for this. One is to gather time-series irradiance data and convert it to MW by collecting efficiency of the solar facility to convert that irradiance into MW. This conversion acts as the solar profile for a particular resource and the NREL database for US entities contains many years of solar data for this purpose. Canadian regions can somewhat be covered by that database, but meteorological data from weather stations may be able to supplement this. The other method is to take historical generation samples from another solar generation facility, gather irradiance data as above, and then merge the two in order to capture some other uncertainties not related to irradiance. Some entities use a solar forecaster to accomplish this task, but many others do this merge of data inside their own company. This latter

[25] http://www.ercot.com/content/wcm/lists/114800/ERCOT_Solar_SiteScreenHrlyProfiles_Jan2017.pdf

method allows site-specific information that is not necessarily the information as detailed in **Table 3.1**, but captures the effects of that table.

Hydro, Wind and Solar Data

Hydroelectric, wind and solar resources are similar in that their production at a given point in time is governed by fuel availability. Hydroelectric resources have varying levels of control over their availability depending on the site; run-of-river generators are entirely dependent on river inflows, while generators with large reservoirs can have daily, weekly, seasonal or even annual storage. The goal of any data collection for modeling the capability of these resources is to find data that give the best representation of the capability of these resources over a period.

For all three resources, there are two basic types of data that can be collected: production data and fuel availability data. At a high level, production data captures the amount of electricity generated over a given period, while fuel availability data captures the amount of primary energy that could have been converted into electricity over a period. For all three resources, the collection of production data is the same, assuming full data availability. For many embedded generators, production data may not be available. Data that can be collected that captures the amount of primary energy that could have been converted into electricity for each resource type is outlined below.

Key Takeaway:
Energy limited resource data gathering should have the same timeframe as the demand collection in the resource adequacy study.

When gathering data for these units, take care to ensure that the same historical time frame is used for the demand sampling. If a different historical year is excluded in the sampling for data in the solar resource, the cross correlation coefficients of the hydro, wind, or solar resource with the demand will impact the end probabilistic metrics in the study. Maintaining the same historical time period as the demand sampling will alleviate the concern over these cross correlations or any other dependency between the resource availability and demand. A good way to think about this is that in times of high irradiance, many air conditioning loads are likely to be active at a given time. If a TP samples irradiance outside of the same time boundaries as the load, the correlations in the shapes need to be described; otherwise, they may be misrepresented in the study.

Solar Fuel Availability Data

For installed solar PV plants, the same irradiance data that created a solar profile can act as a fuel availability curve for that resource. There are various methods to collect irradiance data, with some sources detailed above. A cloud cover or satellite analysis might be necessary to fully determine how those impact the availability of the solar resource to contribute in the resource adequacy study. Some models ask for a temperature and wind speed aspect for solar availability, and any publicly available data source or nearby weather station can have those measurements. In addition to Table 3.1, some models require the Global Horizontal Irradiance (GHI), Diffuse Horizontal Irradiance (DHI), or Direct Normal Irradiance (DNI) or some combination of the three in order to calculate the output of the solar facility. Regarding those values, some weather stations are not equipped to measure all of the values.

Wind Fuel Availability Data

Key Takeaway:
If historical generation records are unavailable for the resource, geographically close profiles are adequate. This includes weather stations.

Wind fuel availability is similarly calculated as the solar fuel availability. However, since wind speed is dependent upon the height of the measurement, the turbine height needs to be accounted for in the gathering of wind speed. The historical wind generation in that area is important in order to get the distribution of wind speeds and thus the generation of that facility. For operational plants, many have wind speed recorders that can be obtained to build the curve. NREL also maintains records for wind speeds between the years of 2012 and 2015; however, recent years are not recorded. NOAA can provide the wind speed for these and other years to supplement the data from NREL. If the operational plant does not record their data, close by weather stations are also acceptable to get the data from. A power curve translates this wind speed curve into a total MW output of the wind facility in order to be used in the study. Other weather data may be required based on the sophistication of the wind model in the resource adequacy study.

For future looking resource adequacy studies, the assumption of geographically close data availability is not always a good assumption. One tactic is to collect the capacity of the facility based on the projected design to assist in ascertaining the availability of the wind resource. The key parameters to procure are the design parameters and associate the parameters to an expected wind MW curve. Design factors to consider include turbine height, cut-in speed, cut-out speed, and other speed breakpoints as well as hot or cold temperature limitations and ice-loading capability of the turbine as based upon the design. As an example, WECC samples historical wind generation from their nameplate and uses that profile at a different wind generation facility in order to supply the wind speed curves. Then any design constraints are applied to that profile to gain the total MW production curve from that resource. In general, for studies that are modeling future wind facilities, a profile of wind speeds from other facilities or meteorological stations along with design parameters from the resource developer can produce the expected MW profile of the wind facility. This process is very similar to the simulated solar PV section above.

Hydroelectric Data

Similar to the wind data, representing energy-limited hydro facilities in the study could require a translation of their water supply into a total energy production. To do so, the resource planner will consider hydrologic or fluvial conditions such as water inflow, outflow, and head of the hydroelectric resource. If using flow data, a power curve is required to translate the water flow into a time series MW on that resource. For these types of facilities, many regulations dictate the amount of water stored or required to be flowing across the facility, so data on spilled water can supplement production data to give a better indication of the availability of the resource to produce electricity in the study. Additionally, only using production data underestimates the potential of the hydro resource. Offer data can supplement the production data to get the energy, operating reserve, or both to express the capability of the unit, as the total capacity of the unit is the current capacity of the resource is the operating reserve the unit is providing added to any current power production. Since hydro facilities have many moving parts, planned and forced outages are also a concern, albeit a lesser concern. Other outages for hydroelectric facilities can also include environmental or safety outages, which have a similar lesser concern in terms of modeling in the resource adequacy study. See Chapter 2 on Thermal resources to find databases that these facilities can report to on outages.

The end goal of data gathering for hydroelectric resources is to build a water year for the amount of water available for the plant to use in generation of electricity and to incorporate any environmental factors, operating restrictions, and generation availability that may limit production based on the sophistication of the model. Unlike other energy-limited resources, more attention can be made to the environmental factors that dictate the amount of flow out of the plant that will describe the availability of the resource. Additionally, if the hydro facility is a run-of-river facility, the inflow of the river and environmental constraints will likely dictate the availability of the plant. Some data sources for the data are Environment Canada, NOAA, and other national weather databases that measure hydrological quality.

Energy Storage Systems

As of this report, two major types of energy storage exist: battery energy storage systems (BESS) or pumped hydro storage. The inputs in **Table 3.2** are important to model energy storage systems. Not all parameters are exclusive to pumped energy storage systems or BESS, though many parameters cross over.

Table 3.2: Energy Storage System Profile Data Requirements

Category	Data Point	What to Gather

Resource Characteristics	Maximum Generating Capacity	The maximum MW the facility can generate when discharging its energy
	Minimum Generating Capacity	The minimum MW the facility can generate when discharging its energy
	Maximum Charging Capacity	The maximum MW the facility can take on when charging its energy supply
	Minimum Charging Capacity	The minimum MW the facility can take on when charging its energy supply
	Dispatch Order	Position in the economically constrained dispatch[26]
	Storage Cycle Efficiency	Total Roundtrip efficiency on the charge or discharge cycles.
	Maximum Energy	Pumped Storage Reservoir or BESS maximum energy storage[27]
Outage and Maintenance Data	Historical Outage Data	Time series MW production and consumption for many historical years
	Maintenance Periods	Time windows where the resource is under outage for maintenance.
	Availability of the Unit	Failure and repair rates of the unit.[28]
Unit Availability during Ancillary Services*	Pumping Operation	Similar to the Outage and Maintenance Data
	Normal Operation	Similar to the Outage and Maintenance Data

*This type of data may be very difficult to obtain for battery energy storage systems as they may have many different ancillary services. An operational profile may be more informative.

> **Key Takeaway:**
> Understanding the energy storage device's operational characteristics allows for adequate modeling, and informs the data collection and databases required for the study.

Initial additions of energy storage systems to systems that are capacity constrained rather than energy constrained are generally capable of providing full capacity value with 4 to 6 hours of continuous operation relative to conventional resources. As an example, an energy storage resource can be charged during low load periods and dispatched during the few highest load hours of the day or by other dispatch patterns depending on how the resource is procured. However, when the penetration increases above 2 to 3 percent of system peak, rigorous modeling of all constraints and capabilities of energy storage systems is required. While the dispatch methodology is still the same, the frequency and duration of high load becomes more binding on the capacity value that energy storage resources can provide since they are required to serve more of the load.

It is also important to note that there are numerous possible interactions of the various energy storage specific inputs. For example, if the dispatch order of energy storage systems is not optimized for reliability, they may need

[26] This is important for Emergency Operating Procedures or other Ancillary Service capacities these storage systems supply. Market data may be required

[27] In pumped hydro cases, this maximum may be quite large.

[28] In BESS systems, this is highly crucial due to the construction of the battery pack. Other energy limited resources have resilient measures in place; however, BESS construction has either a "all or none" capacity.

significantly longer duration capability to provide full capacity value. In addition, if energy storage resources can be used to serve ancillary services, their reliability value can be substantial with even shorter duration capability.

Chapter 4: Emergency Operating Procedures

Emergency Operating Procedures (EOPs) are control actions or tools that system operators can utilize to modify generation or loads under stressed, abnormal or emergency system conditions. These conditions could be resource supply or reserve deficiencies, or element contingencies under the course of BPS operations. EOPs should be properly accounted for and modeled into probabilistic reliability assessments to ensure that a realistic representation of system risk concerning resource adequacy are considered. These tools can be invoked or implemented to mitigate possible resource shortages or emergencies prior to the disconnection of load and the likelihoods of use and amount of relief can vary. The procedures and details of EOPs is widely dependent on a Regional, Area or entity basis and typically occurs under pre-established criteria.

Parameters

Modeling these types of remedial actions can vary greatly by entity and data sources can vary accordingly. EOPs generally, however, will provide a means to relieve a constraint for a specific amount of time. Some types of EOP's that could be considered for studies include:

- Interruption of Transmission Service (Transmission Loading Relief)
- Load Curtailments or Interruptible Load Programs;
- Operating Reserves;
- Use of import agreements with neighboring systems;
- Voltage Reduction;
- Special Resources;
- Demand Response;
- Public Appeals;
- Or, cyclic load shedding.

These types of procedures can have specific parameters that must be considered in modeling. These could include the number of times in a given time period the EOP/resource can be performed, duration and time period between calls, and the amount of relief on subsequent calls or fatigue factors. These constraints can be seasonally adjusted as well depending on the area as seasonal temperatures may prevent an EOP from being enacted on the demand side from a non-disturbed system. With regard to these procedures, state governments or programs may have the details on the limitations and can help to associate the exact parameters required to model that specific type of EOP.

Collection Methods

Due to the rigidity for some EOPs, the duration and frequency are generally fixed indicating a lack of major data collection efforts being needed for a probabilistic study. In terms of data collection, some programs may require a customer to sign up with the utility for the program. As such, for those programs the repository that holds those records will be the source of data for the probabilistic study to determine how much load is relieved when the EOP is enacted. Relevant load relief data (in MW) for EOPs can be determined through several methods depending on the system; however, the majority are based on collection via source documentation or by historical availability.

Key Takeaway:
Emergency Operations Procedures require less data gathering to model than the other topics discussed due to their fixed duration and frequency of calls.

The source documentation methods look at the establishing papers, legislation, or programs that dictate how EOPs will be called upon and use such information as data for study. For instance, some EOPs such as voltage reduction can be determined through the source documents of those schemes. Other EOPs' load relief data can be collected through the registration of resources and the availability requirements for these resources in an emergency. Even further, some EOPs are spelled out in the tariffs, and serve as a good data source for determining the amount of available capacity for load relief. Limitations on number of calls for these EOPs need be considered when collecting the data as well as looking at the assumptions surrounding the source documents to see if both still hold for the study in question. This type of data may not be found in the source documents and should be considered when collecting data for study.

Regarding historical availability methods, the resource planner can also actively collect data regarding how much relief occurred from historical calls to EOPs. Trends could be also reviewed from GADS or other measured data to develop reasonable assumptions for usages for a given EOP if the other methods cannot provide the data. Availability of these resources at the time of the emergency, such as the proportionality to peak loads should be considered when developing assumptions utilizing the availability databases.

Physical Testing or Audits for Voltage Reduction

If physical test are available to the planner, the resource planner can commission a voltage reduction test and utilize those results to determine the amount of relief that the EOP can provide in the probabilistic study. These tests may require other jurisdictional approval prior to conducting the test. Other types of tests may also exist to provide the estimated capacity relief from other EOPs and entities can look to either producing their own test or coordinating with other entities to produce a test.

Chapter 5: Transmission Representation

More and more attention has been given to consider transmission constraints in probabilistic resource adequacy assessment. There are many different parameters associated with transmission lines, and depending on the study, not all of those parameters may be useful in determining the interconnected system's reliability in a probabilistic representation. A majority of the data sources discussed in the other chapters are representative of the desire to determine if sufficient generation is available to meet demand. Similarly, there may be a desire to determine if sufficient transmission is available to deliver that generation to meet demand.

Key Takeaway:
Data requirements depend on the types of transmission model used in the resource adequacy study. Some require additional line parameters, but others require only transfer limits

Interface Limit and Detailed Circuit Representation – Data Requirements

Typically, there are two different ways to represent transmission constraints: interface limit model and detailed circuit representation. In the interface limit model, the transmission is modeled as a "pipe" between two areas with specific constraints and properties. In the detailed circuit representation, the transmission is modeled using all transmission lines that may be seen in positive sequence load flow software into the reliability assessment realm. These types of representations can be useful depending on the type of study being done; however, their data sources may not always be the same.

Interface Limit Model

The transmission constraints between areas are modeled with interface transfer limits. Each interface is represented as a tie line with bidirectional transfer limits. Physically, each interface may consist of two or more transmission lines and the interface limits and equivalent admittances are typically determined based on thorough steady state and/or transient stability analyses. Most of the existing tools for resource adequacy assessment are able to simulate random forced outages on the interface between areas. The minimum data required for representing the interface limits depending on the purpose of assessment and the method employed for network flow analysis. **Table 5.1** shows the minimum data requirements for using the Interface Limit Model to incorporate transmission constraints in resource adequacy assessment. NERC TADS is a database that records the type of outages associated with transmission lines and provides enough information to formulate a forced outage rate for the transmission elements. Aggregation techniques will be required to associate the specific line data with how the transmission is modeled as the records in TADS may be more specific than the tie line representation. In order to find the bidirectional transfer limits, generally an Available Transfer Capacity (ATC) study can inform on the limiting conditions and the results of that study will provide a "source to sink" capacity between areas, which is very conducive to modeling these interfaces. If adding in the DC powerflow capabilities of load flow software, the equivalent reactance between the source and sink in that ATC study will need to be determined and provided. This may not always be provided in a single ATC study, so model reduction of the powerflow data collected for Interconnection-wide base cases created under NERC MOD-032[29] can aid in finding the equivalent reactance of the interface.

Table 5.1: Minimum Data Requirements (Interface Limit)

Network Flow Method	Import/Export Limit	Equivalent Reactance	FOR
Transportation Model	Yes	No	Maybe
DC Power Flow	Yes	Yes	Maybe

[29] NERC MOD-032 can be found here

Detailed Circuit Representation

Normally detailed transmission models are not required in resource adequacy assessment. If detailed circuits are modeled with generation facilities, the evaluation is often referred to as composite system reliability assessment and a vast number of input data are needed for such assessment. Composite system reliability assessment mainly involves the selection of possible system states for evaluation and the assessment of the consequences of these states. Two basic methodologies are used in the system state selection in composite system reliability assessment. These are analytical contingency enumeration approach and Monte Carlo simulation method. The system analysis in assessing the consequences of selected outage states is the same for both analytical and Monte Carlo simulation methods. AC or DC power flow is employed to determine if a particular state is a success or a failure in composite system reliability evaluations.

The detailed power flow data for composite system reliability assessment typically contains information on the system topology, equipment ratings and various potential operating conditions for example summer/winter, peak/light load, drought/wet or export/import scenarios. These power flow data are maintained and updated by industry regularly. Outage statistics data such as the failure rate and average outage duration for all of the composite system facilities are recorded and available from NERC GADS and TADS systems for generation facilities and transmission facilities. Some system specific data such as remedial action schemes for example fast runback of HVDC, normal operating procedures, tapped transmission lines and common mode outage information may be needed. The general procedure and the minimum data requirements for composite generation and transmission reliability assessments are available in existing literature[30].

30

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Chapter 6: Concluding Remarks

Based on the current methods for setting up a probabilistic resource adequacy assessment, the PAWG identified a few commonalities that are of particular importance. While different studies may require additional data if they wish to study the impacts of a particular risk, for instance cyber-related attacks, the document provides different collection experiences and highlights the key points of resource adequacy studies. In particular, the PAWG identified a few common practices that should be emphasized. In general, the probabilistic studies require large quantities of data to add more complexity to the models in their assessments[31].

The Need for Data in Probabilistic Studies

In general, a resource planner's job is to predict and determine the level of risk for future years. They require a set of predictive models that they develop and maintain. In order to develop and maintain their models, they require access to a variety of different types of data that may not be generally made available. This particular point is crucial, as sometimes engineering judgement is able to fill where data is not available; however, judgement is not a substitute for high quality data sources that are representative of the equipment being modeled. This need for high quality data applies to all the different categories of data in the previous Chapters and is not relegated to demand, generation, transmission, etc. Additionally, the study objective may change the modeled parameters based on the engineering judgement of the resource planner. In any two given studies, certain resources or aspects of a resource may not be a necessary modeling requirement due to the study objective. The resource planner needs to determine the model complexity required for the loss-of-load probabilistic study and use the data sources appropriately to complete the model.

Common Key Points

The PAWG identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- When utilizing GADS or other historical outage reporting data, the thermal resources future outage rate may not be indicative of this historic metric especially when the facility moves to different operational characteristics.
- Battery energy storage systems (BESS) can be modeled similarly to other energy-limited resources such as pumped hydro when performing a resource adequacy assessment, with an emphasis on understanding the operational characteristics of the BESS.
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

Possible Future Work

As probabilistic resource adequacy studies develop and mature, the PAWG recommends that the ERO review this data collection document. By doing so, this document can be utilized along with other probabilistic resource adequacy

[31] This assumes that no assumptions will be made regarding the effect these new facets of the model have on the availability or performance of the element in the resource adequacy study.

documents to assist entities with developing new probabilistic requirements or improving previous ones. Additionally, the PAWG found the following recommendations:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting databases, the thermal resources future outage rate may not be adequately represented by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions. Some entities do not have access to data sets to feed their models, and the need for more accurate studies may require access to data outside of those publicly available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.
- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Appendix A: Overview of General Data Management

In general, data used for study should be complete, of high quality, and representative of the equipment under study. As with many other modeling issues, there are times when the data is not always complete, does not follow the guidelines for data submission in the database, or is not accessible without supplemental agreements. This appendix covers some of the general considerations for vetting the data for use in the probabilistic study.

Keeping Data Aligned

When the resource planner is merging many different sources of data or when dealing with large data sets, a few common procedures should be followed. Considering much of the data in probabilistic studies is based on a time series, or has a time dependence (such as weather years), many of the processes deal with this type of alignment. Some general data alignment techniques for entities to consider are listed below:

- Convert to a common time zone, including considerations for daylight savings time changes (if applicable).
- Utilize hourly trends to fill gaps in data, such as zeros and/or blank hourly values due to time zone conversions. These gaps should not be large in size, nor should they be frequent in the data source[32].
- Detect unit outliers in minimum and maximum daily, monthly, and annual peaks for possible data errors.
- Determine the per-unit relationships between hourly values and the daily peaks throughout the years in order to detect anomalies.
- Conduct benchmarking to similar data sets such as, but not limited to, entity reported actual summer and winter peak demands for use in Regional Reliability Assessments[33]

Common Sense Validation Checks

Additionally, there are a few other common sense checks when preparing the data for use in a probabilistic study. This list is provided as an example, and other checks or metrics may exist for determining how trustworthy the data source is for providing information in a resource adequacy study. Examples of such checks are found in **Figure A.1**.

[32] For example, some data sets are not usable with more than five percent total data missing or when the largest gap of data is longer than 12 hours. These values will change depending on the data. In general, a resource adequacy study can fill these gaps; however, these two metrics should be considered when vetting a data source.

[33] A common NERC approach for determining load forecast uncertainty uses the variance in year-over-year deltas of actual peak demand. For this reason, a good sanity check is to compare these deltas from FERC 714 for particular entity or area with that of another data set.

Peak Data

- Correctly filled out field
- Correct mangitude
- Correct units

Energy Data

- Correctly filled out field
- Correct mangitude
- Correct units

Load Growth

- Reason provided for growth exceeding +/- 1%

Resources

- Resource in the right Zone, Balancing Authority, and Organization
- Unit Type matches with fuel (e.g. PV unit with secondary battery incorrectly labeled as a gas turbine)
- No negative or zero capacities for nameplate or seasonal capacities
- Status Code, NERC Class Code, and WECC Class Code are consistent
- No duplicate resources

Reserves

- No blank or null values provided
- Data is consistent with other portions

Hourly Data (Demand, Hydro, Wind, Solar)

- Plotted data do not contain gaps
- Plotted data are consistent with request
- Plotted data demonstrate no abnormalities (e.g. jump discontinuities of large magnitude)

Transmission

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Trasnformer

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Figure A.1: Common Sense Checks for Data Validation

Data Retention for Future Studies

Due to the large set of data required to gather for modeling resources in a resource adequacy study, it is preferable to store much of the data for use in future studies. For instance, the transmission system representation, once built, does not need to request the same level of information at each time the model is updated; a notification of which elements, interfaces, or other equipment that have changes suffices. Additionally, outage data do not need to always be collected for the same period. The collection effort should be focused on the data that would supplement what has historically been collected. Because of these, a data maintainer should be used to ensure that the data are not lost, mutated, or otherwise changed between studies. Additionally, some data can be used for different studies, further increasing the value of retaining large sets of data for probabilistic reliability studies.

Appendix B: Example GADS Data Request Example Forms

This Appendix serves as an example, data forms when requesting GADS data from other entities. ERCOT has graciously provided the following two forms to provide clarity on some of the information in the chapters.

GADS Data Request Notice

The following information is contained in ERCOT's GADS Data Request Notice and an example data, the form they send to other entities to request data that accompanies the notice. All content provided is to be used as an example for these requests and should be used only where appropriate.

NOTICE DATE: January 31, 2020

NOTICE TYPE: W-X013118-01 Operations

SHORT DESCRIPTION: Requested data for the Planning Reserve Study

INTENDED AUDIENCE: Resource entities

DAY AFFECTED: April 1, 2020

LONG DESCRIPTION: ERCOT is conducting a capacity planning reserve study in 2020 that is mandated by the Public Utility Commission of Texas, as well as a loss-of-load study for the North American Electric Reliability Corporation (NERC). In order to accurately model historical thermal unit availability for both studies, ERCOT is requesting that Resource Entities extract from the NERC Generating Availability Data System (GADS) certain unit-specific outage data for each of their thermal Generation Resources, and provide that data as instructed in the attached data submission form. ERCOT is requesting up to two Calendar Years (2018-2019) of GADS outage event and Equivalent Forced Outage Rate (EFOR) data for units that meet the following two criteria:

A. GADS data was submitted to NERC for Calendar Year 2018. (Wind unit outage data uploaded to the NERC GADS Wind system is not to be included in the submission.)

B. The thermal unit(s) are currently expected to be in operation, or could potentially be in operation, as of January 1, 2021.

The GADS data submissions are considered Protected Information under Nodal Protocols Section 1.3.1.1(q).

ACTION REQUIRED: Please return the attached data submission form and any accompanying data files, by April 1, 2020, via email to ClientServices@ercot.com.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

If you are receiving email from a public ERCOT distribution list that you no longer wish to receive, please follow this link in order to unsubscribe from this list: http://lists.ercot.com.

GADS Data Submission Form

REPORTING INSTRUCTIONS:

1. An example GADS Data submission form ERCOT is required for all units that meet reference. Please use this as an example when improving or building similar GADS data requests. An important piece of the following two criteria:
    a. GADS "Conventional" data was form is the capability to categorize the submitted for Calendar Year 2018; wind data to each utility, unit, and solar units reported do not need to be included event in your data submission.
    b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact order to feed the information for the preparer of into the data submission in case ERCOT staff has questions on the submitted GADS data probabilistic model.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link.
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

REPORTING INSTRUCTIONS:

1. Data submission is required for all units that meet the following two criteria:
   a. GADS "Conventional" data was submitted for Calendar Year 2018; wind and solar units reported do not need to be included in your data submission.
   b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact information for the preparer of the data submission in case ERCOT staff has questions on the submitted GADS data.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).**Respondent Contact Information:**
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link. Contact Person:
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

Title:
Telephone Number:
Resource Entity Name:
Email address:

Utility Code	**Unit Code**	**Unit Name**	**Year**	**Event Type**	**Start of Event**	**End of Event**	**Net Available Capacity**	**Cause Code**	**Event Description**

Utility Code	Unit Code	Unit Name	Year	Annual-EFOR	EFOR-Jan	EFOR-Feb	EFOR-Mar	EFOR-Apr	EFOR-May	EFOR-Jun	EFOR-Jul	EFOR-Aug	EFOR-Sep	EFOR-Oct	EFOR-Nov	EFOR-Dec

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Data Collection

Approaches for Probabilistic Assessments Technical Reference Document

~~January~~ June 2021

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Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

This document identifies and considers general categories of data inputs commonly used in loss-of-load probabilistic assessments across industry. These include data considerations with focus on parameters and collection methods for demand, thermal resources, energy-limited resources, emergency operating procedures (EOPs), and transmission representation. Entities must consider procuring or obtaining enough data to accurately represent the model parameters or inputs to effectively develop and run a probabilistic reliability study[1]. An entity wishing to conduct a probabilistic study should thoroughly review these data inputs and assumptions, the technical nature and aspects of the model inputs in study, and the soundness of the results with all stakeholders as a standard operating practice. This document separates each of the identified major categories in a resource adequacy study and highlights the types of data, possible sources for the data, and other qualifiers associated with the inclusion of such information in a probabilistic study.

Key Points and Possible Future Work

The Probabilistic Assessment Working Group (PAWG) identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- An in-depth understanding of operational characteristics of the resources represented in a study is needed to determine the requested data points in order to study the resource.
    - ~~Data for r~~Resource performance during ~~forecast~~ ambient conditions (e.g., cold-weather or hot-weather performance) is of particular concern. Resource performance should be consistent with the weather – related conditions assumed in the case under study. ~~Probabilistic generator availability data may not be evenly distributed across all scenarios.~~
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This dependency between quantity of data needed for the transmission elements is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Battery energy storage systems (BESSs) can be modeled similarly to other energy-limited resources such as pumped hydro, with an emphasis on understanding the operational characteristics of the BESS.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

The PAWG also highlighted the following objectives for possible future ERO work to be further explored and addressed as needed:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting data, the thermal resources future outage rate may not be adequately ~~representing~~ represented by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions.

[1] In terms of reporting results and the metrics associated with probabilistic studies, the PAWG has published a separate document here. ~~[NEEDS LINK]~~

Commented [JS1]: From Wayne Guttormson:
"I have no substantive comments. Report was an interesting read, and the content was good."

Commented [JS2R1]: Thank you for your comment!

Commented [JS3]: From Robert Reinmuller:
"Lots of information presented, however it is a bit of a difficult read and the document appears fragmented. There is no specific criteria or a specific plan of action provided for the use of this data by the regional entities"

Commented [JS4R3]: NERC Publications will perform a review to ensure adequate flow across the document. Technical Reference documents are "Documents that serve as a reference for the electric utility industry and/or NERC stakeholders regarding a specific topic of interest. These deliverables are intended to document industry practices or technical concepts at the time of publication and may be updated as deemed necessary, per a recommendation by the RSTC or its subgroups to reflect current industry practices." Per the RSTC charter. As such, no specific plan or action is provided.

Commented [JS5]: From Robert Reinmuller:
"Document 1_10 is generally well written and at a fairly high level. Writers may want to read the material to refine the flow so that the content does not appear fragmented. "

Commented [JS6R5]: Thank you for your comment. NERC Publications will perform a review to ensure adequate flow across the document. Additionally, this document was constructed in a manner that tends to a more loosely connected, but highly technical chapters when gathering data for a probabilistic study.

Commented [JS7]: From David Jacobson:
"Footnote 1 needs link"

Commented [JS8R7]: Added Hyperlink.

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Commented [JS9]: From Robert Reinmuller:
"The document listed various available sources of data, however they are in a variety of databases and it will take time to compile and maintain. It may be beneficial to provide data collection guidelines to ensure that databases are built on consistent, transparent, and common assumptions otherwise it will become huge task for most."

Commented [JS10R9]: This document was not altered to provide data collection guidance as it is a reference document. The PAWG agrees that there is a large effort to maintain databases such that the data contained in them are useable in studies. The PAWG will consider writing guidance in this area as a separate work item.

Commented [JS11]: From Robert Reinmuller:
"Modeling all resource uncertainty may shift the resource adequacy planning challenge away from reliability needs toward economic considerations. The dilemma of designing or operating the system to avoid high impact events, even though the event probability is low will still to be addressed. Presently, clear criteria for doing so are generally lacking. Because these events usually involve the loss of multiple elements, the calculated event probability becomes small and therefore the economic impact will be also small and limit the investment that can be made to address such an event."

Commented [JS12R11]: This document focuses on the system reliability of modeling the resource adequacy and availability in probabilistic studies. The uncertainties used to model resource availability in these studies will have some sort of economic impact. The NERC PAWG works with reliability issues on system operation and design and does not touch on the economic impacts of the events mentioned in the comment. In regards to the clear criteria for assessing high impact low probability events, if this is someth ...

Some entities do not have access to data sets to feed their models, and the need for more accurate studies may require access to data outside of those public~~al~~ly available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.

- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Introduction

Today's electricity industry is under a period of significant transition. NERC and the ERO note several high-level trends that have affected the North American Bulk Power System's (BPS) planning and operations, such as the continued retirements of traditional baseload resources accompanied with the proliferation of renewable and other forms of variable generation. These trends have highlighted an increasing need for the industry to properly model, study, and plan for the future state and reliability of the grid. NERC and the ERO recognize that these trends are highly variable and carry increasing uncertainties, which further emphasize the need to enhance the traditional and deterministic forms of resource adequacy and reliability assessments. As was identified in the 2019 NERC Long Term Reliability Assessment (LTRA)[2] and the 2019 NERC State of Reliability report (SOR)[3], NERC looks to enhance its resource and transmission adequacy assessments by incorporating more probabilistic approaches in carrying out its mission of a highly secure and reliable BPS. To further that result, NERC continues to promote the use of more probabilistic approaches into reliability assessments providing further insights into assessing the adequacy and reliability of the BPS.

The NERC Probabilistic Assessment Working Group (PAWG) was tasked to explore and highlight the current data collection processes across the industry that are used to produce loss-of-load probabilistic studies that assess emerging reliability risks. This document explores and identifies requirements, sources, and techniques for obtaining and modeling data for possible usage in conducting probabilistic assessments. The objective of this document is to discuss and raise awareness of probabilistic methods and techniques available to assist entities in conducting reliability assessments of systems with resources of increasing performance uncertainties. This document supports the group's mission to promote the usage of probabilistic techniques and studies in carrying out NERC's mission.

While NERC has historically assessed resource adequacy using deterministic planning reserve margins, the purpose of this document is to discuss data collection considerations for a probabilistic assessment. The intended audience is the industry at large with the objective of raising the collective awareness of available data collection methods. This report is written as a reference document for industry participants to understand the options available for these data sources and to highlight any benefits or considerations that methods require.

In spring 2017, the PAWG conducted a survey of Registered Entities to better understand their assessment capabilities and identified challenges as they relate to probabilistic resource adequacy assessments. One of the recurring themes of survey responses was the challenges with selecting and managing large sums of data in order to develop realistic inputs to probabilistic models. The 2019 LTRA Key Findings indicate that future probabilistic assessments should incorporate the increasing uncertainty of resources and demand while also considering the increasing amounts or sources of data. The PAWG has developed this document to further assist entities wishing to or whom are actively engaged in conducting probabilistic assessments. The PAWG welcomes and invites subject matter experts' discussion and comments to this document to further develop widespread industry participant knowledge, application and acceptance of probabilistic studies and methodologies to assist in meeting the challenges posed to the electricity sector. This document is intended to complement ongoing industry work as there may be other groups that rest outside of NERC that are engaged in data collection discussions and probabilistic approach developments. As technical discussions and methods evolve further, the PAWG will update this document to meet industry needs.

There are numerous public and private sources of data that entities such as Planning Coordinators or Transmission Planners (TP) can use to develop a probabilistic study. NERC plays a valuable role in providing some of these sources via the NERC Generating Availability Data System (GADS) and Transmission Availability Data System (TADS); however, these are not the sole sources of data for a probabilistic study nor are they sufficient for every probabilistic reliability

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[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf
[3] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2019.pdf

study. Many NERC Regional and Registered Entities utilize different models for their probabilistic reliability studies and this document attempts to summarize the collective approach and basic data needed to perform this work. Depending on the tools available to the entity, additional data from other sources may be required as the models available to that platform may require more information than the data source collects.

Chapter 1: Demand

Demand modeling in a probabilistic resource adequacy study is typically conducted through a combination of several inputs, including the utilization of historical data, demand forecasts, ~~uncertainties~~uncertainties, and assumptions specific to the system under study. Demand or load shapes can be modelled based on historical monthly or hourly peak demand profiles and shapes, scaled to reflect forecasted conditions. In many cases in this chapter, the word "demand" and "load" may be used to reflect the modeling of end use customer MW draw. In the case of "demand", the emphasis is on the MW amount and its time distribution, while the term "load" can encompass other complexities outside of "demand," which may indirectly capture demand acting as a resource to offset the electrical system's draw at that time. Some models may not have the complexity to identify the nuances between the two terms, or some definitions may not be as clear as the above distinction. However, in terms of the data, most of the sources and procedures will not vary between "demand" or "load" and the terms can be used in the following chapter interchangeably.

Demand Considerations

In a probabilistic resource adequacy study, accounting for specific assumptions regarding the amount and uncertainty of demand plays a significant impact on probabilistic indices results. Entities should consider the use of multiple demand level scenarios in assessing the resource adequacy of their systems under study. An example of these demand levels could be specific forecasts, such as 50/50 or 90/10 system forecasts that represent~~ing~~ the probabilities of exceeding explicit levels. Different techniques can also be employed using statistical calculations, such as probability-weighted averaging. Probability-weighted averages calculate load level indices with corresponding probabilities of occurrence, thus representing the uncertainty in system demand due to external inputs, such as weather and economic factors. An example of this could be by using distributions of monthly peak demands versus the annual system peak demands. The selection and usage of multiple load levels can assist entities in planning against uncertainties, such as the occurrence of more extreme demand conditions or extended stressed system conditions. To gather some of these selections, a demand curve can be developed. To build demand curves, the RTO/ISO can utilize their metered data, as the granular data provides an easy way to sample the demand.

Demand Curve Selection

Demand can follow many different socio-economic causes that would shift the shape of the demand curve in a multitude of ways; however, weather or climate is commonly identified as a primary driver of demand impacts. To help mitigate this, the demand curve should be constructed by considering the impact of differing weather conditions to better capture temperature sensitivity. Some of the considerations for selection can include ambient temperature for seasonal conditions, wind speed, and precipitation. Each of these meteorological markers has demonstrated impact onto the demand curve and should be considered when gathering data surrounding demand during those time periods. Specifically related to the curve construction, the peak, nadir, and ramping rates have substantial influence on the reliability impacts to the system in study[4]. Accurate characterization for those periods is important for the planning and scheduling of generation and ancillary resources during the study.

Commented [JS13]: Should we mention the Energy Reliability Assessment Task Force(ERATF)?

Commented [JS14R13]: Currently, the ERATF is working on documents that have no draft published for the reader of this technical reference document. No link to the ERATF was added.

Because the resource planner desires to capture a full distribution of possible demand conditions, the demand curve selection is important when collecting a proper sample of data. These conditions include cool, average, hot, and extremely hot summers; warm, average, cold, and extremely cold winters; and low, average, and high meteorological conditions such as irradiance or wind speed. These will emphasize some of the peaks, nadirs, and ramping rates. Accurate characterization of the identified risk depends on the samples taken and the selection of the curves those samples produce. For instance, if the demand data collected contains 25 years of curves selecting those curves that accentuate the peaks, nadirs, and ramping rates will allow the resource planner to more accurately capture the

[4] Historically, the planning process typically accentuated peak conditions. As risk moves away from the on-peak periods (over a season or a day), looking at curves that accentuate other aspects of the demand curve is warranted.

anticipated risk conditions of the peaks, nadirs, and ramping rates. In the same light, selecting all the curves will weight all years as equally probable.

Load Scenarios

Loading level directly determines the required amount of resources in the study due to the load and generation balance. In addition, the load level and composition play a significant influence on the system in study. When performing a resource adequacy study, a TP/PC must select the appropriate scenarios that either stress or relate demand to differing extreme conditions. In order to do this, planners will need to gather demand data associated with the weather conditions specified above. More specifically, this will be a distribution of load scenarios across demand curves. One example distribution is cool, average, hot, and extremely hot summers along with warm, average, cold, and extremely cold winters. Couple those scenarios with high, average, and low wind speeds as well as high, average, and low precipitation (or water flows) and a diverse amount of scenarios are available for selection in the study. As many of these scenarios are study dependent, the specific study scope can assist in either paring this list down or adding to it. Additionally, sensitivities can also accentuate specific loads and can assist the planner in studying the impact to their system. For example, a load scenario that assumes very aggressive electrification of the transportation system will accentuate the usage of demand during the hours in use, as well as on the days of the week that transportation is more heavily used.

Load Forecast Uncertainty (LFU) Considerations

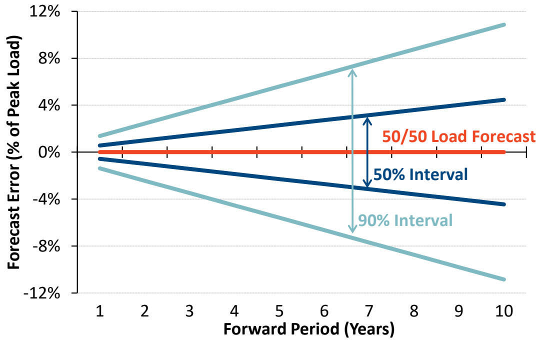
Realized load can differ from projected load for multiple reasons. First, because weather cannot be exactly predicted and will cause peak load to differ from the normalized-weather forecast (as discussed in the ~~weather~~ weather-related LFU section). Second, because there are uncertainties in population growth, economic growth, energy efficiency adoption rates, and other factors. Data for these topics can be regulatory based and would vary by jurisdiction and program. These non-weather drivers of load forecast uncertainties (LFUs) differ from weather~~-~~ related LFUs because they increase with the forward planning period, while weather uncertainties will generally remain constant and be independent ~~with~~ from the ~~forward~~ period being studied.

Non-Weather Related LFU

From the above, the uncertainties in population growth and the associated demand forecast can be addressed by a statistical approach at quantifying the uncertainty. To best illustrate this, consider this example. For each weather-year load forecast, five non-weather load forecast uncertainty multipliers are applied to all load hours. **Figure 1.1** shows the uncertainty as a percentage of the 50th percentile (P50 or "50/50") peak load forecast, indicating that the forecast uncertainty increases as one moves further into the future. Each multiplier is assigned an associated normal-curve-based probability with the sum of the probabilities totaling 100 percent. **Figure 1.2** shows the three-year forward load forecast uncertainty multipliers[5]. To calculate the weighted-average results across all load scenarios, the weather-year probability weights and the non-weather probability weights are multiplied to create joint probability weights. More details about non-weather load forecast uncertainty can be found in other reports in the industry[6].

[5] While the figure shows symmetric forward LFE, these points may not be symmetric.

[6] A few relevant reports are posted on the Electric Reliability Council of Texas (ERCOT) website, which contains material listed here: http://www.ercot.com/content/wcm/lists/114801/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf; http://www.ercot.com/content/wcm/lists/167026/2018_12_20_ERCOT_MERM_Report_Final.pdf; http://www.ercot.com/content/wcm/lists/114801/ERCOT_Study_Process_and_Methodology_Manual_for_EORM-MERM_12-12-2017_v1.0.docx



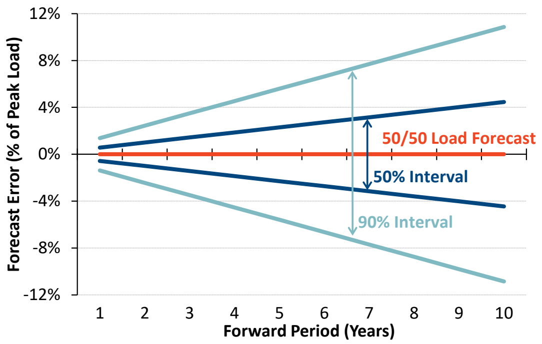


Figure 1.1: Non-Weather Forecast Uncertainty with Increasing Forward Period

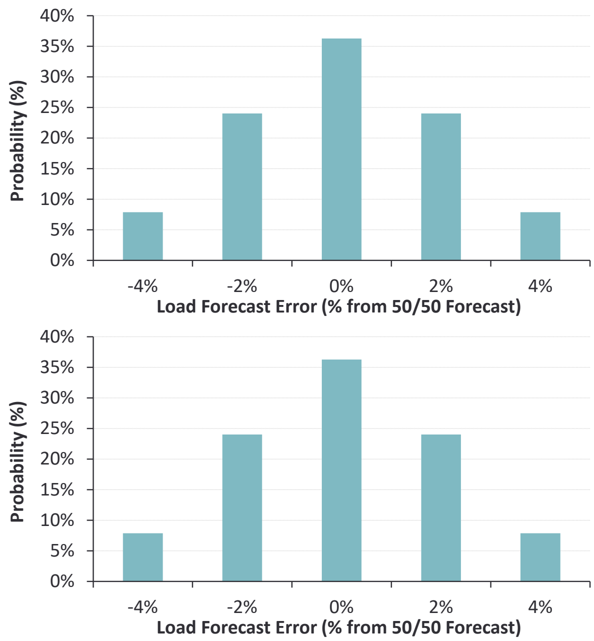


Figure 1.2: Three-Year Forward LFE with Discrete Error Points Modeled

~~Weather~~ Weather-Related LFU

While LFU methods have the ability to capture many uncertainties related to the load, weather factors are a significant driver of load and their uncertainties can be captured when undertaking a probabilistic assessment. The ~~weather~~ weather-related methods described below can be utilized to capture the uncertainty with respect to year-over-year differences. Typically, weather-related LFU captures the variance of conditions documented in the historic conditions. If the study desires to simulate extreme conditions outside of what historic conditions can predict (e.g., sustained higher than record wind speeds) the resource planner will need to adjust or produce data that captures those conditions[7].

Some data points to consider are ambient temperature, dew point, wind speed, and cloud cover across a variety of stations in the geographic region associated with the assessment area. These variables have been determined to relate to the variance in load, and one of the sources of data on those variables is ~~at~~ from weather stations. To provide enough accuracy to depict the ~~weather~~ weather-related LFU, multiple years of weather are required to capture this uncertainty. The Independent Electricity System Operator (IESO) currently uses 31 weather years and runs the load model forecast on those years shifted up to seven days to account for each numeric day falling on a given day of the week. That is, day 100 will lie on a Monday, Tuesday, Wednesday, Thursday, Friday, Saturday, and Sunday to account for differences the load has based on temporal shifts. This equates to 465 distinct weather simulations[8] and from there, the Load Forecast Uncertainty could be determined. Other entities, such as Argonne National Labs, have taken

Commented [JS15]: Is this a place to consider "extended stress scenarios"? One or two extreme temperature days has a different LFU than an extended period of extreme temperatures.

Commented [JS16R15]: If the weather temperature peaks in the historic data are documented, the use of multiple weather years should capture these extreme weather days. Verbiage added for study conditions that weren't experienced (e.g. record high or low temperature or wind speed.)

[7] Note that this type of adjustment would need to be study-wide in order to have consistent study conditions for these extreme weather scenarios. This does not; however, adjust the data collection technique for weather-related LFU.

[8] Seven days forward, seven days backward, and the day that the historic measurement was taken multiplied by the number of years. For 31 weather years, this is (7+7+1)*31 = 465.

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the information at weather stations and numerical weather prediction (NWP) data coupling to determine the weather-related LFU.

SERC gathers this weather information from FERC Form 714 Part 3, Schedule 2[9]. This source is by no means the only resource for ~~weather~~ weather-related uncertainty, as there does exist data through metering at the ISO/RTO level. The ISO/RTO granular data opens up more ways to construct the LFU, similar to the benefits in the demand section above. The FERC data source requires that the Electric Utility Planning Area provide hourly demand levels in megawatts and the source starts at year 1993 for some regions. The format changes based on the year as per Table 1.1.

Table 1.1: FERC Data Source Format

Reporting Year	File Format	Notes on Use
1993 to 2004	.zip files organized by reporting year and NERC regions (legacy and current). Microsoft Windows compatible programs to read spreadsheet and text files, there exists a file that needs conversion in the archive, but many programs exist to convert to Microsoft products. Each entity has a separate format for each	Ensure that the data conversion you use for .wk1 files can be converted to Microsoft Excel. No viewer exists and must download to view the data. Conversions for analysis regarding multiple entities are needed to ensure the data gathered is uniform in the study.
2005	Similar to 1993 to 2004	Individual Entity filings can be viewed through the FERC eLibrary
2006 to present	All responding entities have the data and have the .zip archive to download. That archive contains .csv file formats	FERC Form Viewer is able to fully visualize the data prior to download. This year a unified format is applied across entities

It is suggested that the data be converted to a daily hour ending (1-24) matrix format. In order to perform that conversion, a few cleansing techniques can be utilized. Associated hourly trends and other whole filling algorithms will help to complete the database when holes or incompatible formats occur when adjusting time zones. To assist, FERC has placed a relational database viewer to assist with the collection of this data. See **Figure 1.3** for the database schema provided. Additional screening approaches to detect anomalies with the data that include outlier detection are also needed to ensure a good quality data set prior to utilization in the study.

[9] https://www.ferc.gov/docs-filing/forms/form-714/data.asp?csrt=1824067088296503636

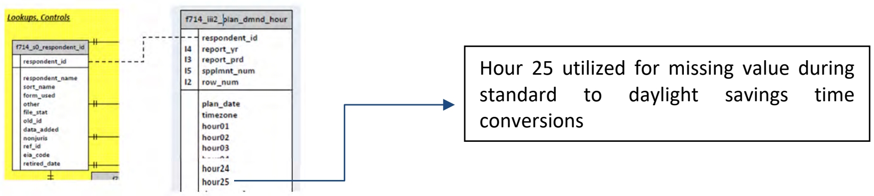

Figure 1.3: FERC Database Schema

In addition to just these hole filling requirements and other changes as required for outlier detection, additional screening approaches are needed~~need~~ to reconstruct the data relationships. An example of what SERC has done to additionally adjust the FERC database forms can be found in **Figure 1.4**. As shown, the additional approaches can impose a slight difference between the NERC Long Term Reliability Assessment (LTRA) data and what is filed in the FERC database. For probabilistic studies, it is best to use the data in the LTRA (i.e., post additional screening) in order to calculate the ~~weather-~~ weather-related LFU.

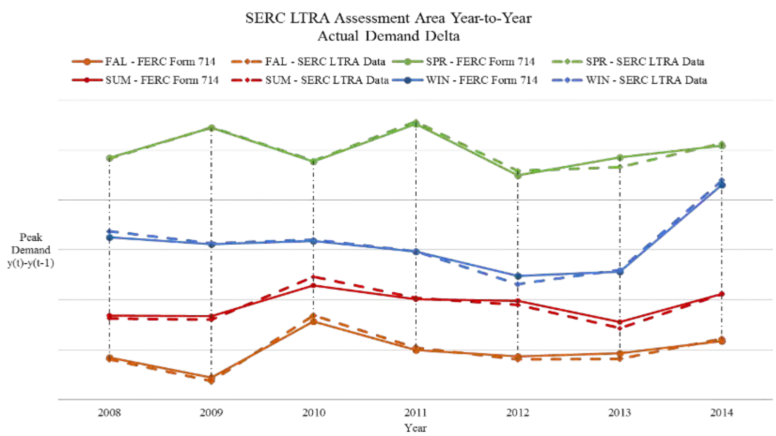

Figure 1.4: SERC Adjustment Example Utilizing FERC Databases

Complexities in Modeling Demand

While the basics of demand modeling in probabilistic studies is detailed above, multiple issues arise when allocating operational characteristics and other contractual obligations into the probabilistic study. Some of these complexities arise especially during the NERC Probabilistic Assessment process and are reflected in the following sections.

Modeling Multi-Area Systems

Entities should consider the correlation of peak demands with neighboring area systems in developing composite load shapes. These periods, perhaps due to heightened weather or economic conditions, represent high degrees of peak load correlations and represent the highest amount of coincident demands. The highest coincident peak demands represent a conservative assumption in the ability of the overall system to meet demand by reducing the ability or reliance of neighboring systems assistance in meeting peak loads. To capture this in the probabilistic study, load shapes from different Assessment Areas' geographic boundaries should have the same time frame as the study. Sometimes these regions change their boundaries; however, the goal is to stay consistent across the study in terms of data quality feeding the different geographic regions in the study. In cases where the boundaries of the probabilistic study cross different Assessment Area's geographic regions, data should be coordinated to capture the system coincident peak as a composite of the many geographic regions in the study.

Demand Response (DR)

For the probabilistic incorporation of demand response, the particular mechanics of each program or structure will dictate the utilization of the demand response. Primarily of concern is the amount of load relief the demand response provides at every stage, the number of times the resource can be called in a given period, and any other limitations on the duration or amount of relief the response[10]. For regions where this is required to be registered, the above information can be found on the registration forms; however, not all regions are able to provide those registration forms. In these areas, the program can define many of the parameters; however, historical usage information can solidify the amount of load relief at each demand response tier. This historical usage however may be affected by more parameters than just the load relief as certain connections or disconnections affect the availability of the demand response to achieve the load relief. As these are quite complex, the PAWG recommends using a data source that captures operational conditions surrounding demand response in order to capture any cross correlations, or to calculate them otherwise.

For demand response that is registered, the amount of relief, number of times it can be called, and other duration limitations or restrictions are found in that registration forms to enter into their respective databases. For unregistered resources, resource planners are encouraged to use methods to predict their availability by analysis of past performance and heuristics going into the future to obtain these values. A quick overview of the data inputs for demand response are summarized in **Table 1.2**.

Table 1.2: Information Required for Demand Response (DR)

Information Required	Example Collection Source
Amount of load relief	Registration database that aggregates the load relief or informal survey to non-registered devices
Number of times in a given time period demand response can be called	State/Provincial level orders or similar utility contracts regarding Demand Response
Duration limitations	State/Provincial level orders or similar utility contracts regarding Demand Response
Tiers of response	State/Provincial level orders or similar utility contracts regarding Demand Response
Other restrictions	Utility specific directives, databases on controllable loads

In addition, there are market structures that contain different levels of this type of demand response. These are sometimes labeled as Emergency Response Service (ERS), but these are going to be varying by when they can be called and the response of the service. Supplemental collection of similar sources[11] should be utilized to capture these tiers of response.

[10] For example, one of the more difficult considerations in Demand Response is the expected performance versus actual performance during extreme temperatures.

[11] State or other regulatory bodies as well as other internal sources may manage these sources.

Commented [JS17]: Should actual performance vs. expected performance be considered. For example, can/will customers override demand response during extreme temperatures?

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Demand and Demand Response as a Resource

When demand response is modeled in the demand profiles themselves~~, adjustments~~, adjustments to the demand profile will apply to the demand response. Conversely, when demand response is modeled as a resource, it is not included in the demand profiles and is not included in any of the alterations in the demand section. To further clarify the difference, when DR is modeled as a resource, adjustments from the weather or non-weather related LFU will be only on demand rather than both the DR and the demand. This can then be directly used in the study as all of the adjustments are on demand curve. When modeling DR as a resource, these techniques need to also be applied to the demand response modeled as a resource as such LFUs will impact the key model parameters in **Table 1.2**. The data source chosen to provide the LFU should be flexible to adjust for either modeling scenario. The key point for this separation is to ensure any adjustments to demand are adjusting the operational characteristic of the demand response or the demand, rather than both. If separating the demand response as a separate resource, then the collection of data may require more data than just the amount of load relief at any given time in the simulation and may require time-of-use or other operational profiles to determine in-simulation output of the demand response when called upon.

Distributed Energy Resources (DER)

DERs can be a multitude of differing resource types connected through the distribution system; however, many of the current installations are photovoltaic solar (Solar PV). Some probabilistic studies utilize simulated profiles as a load modifier in performing the load forecasts. In some areas, a DER forecast may be available, but these forecasts are generally at the state regulation level. As such, the forecasts may vary between Assessment Areas, and could even vary internally to the Assessment area if such boundaries cross state lines. Such data can be valuable to the planner when performing the probabilistic assessments, but ~~should~~ care needs to be taken such that the DER are not double counted in the demand portion of the study. That is, if a load modifier for simulated profiles ~~are~~ is used; additional forecasts should not double count this modifier. See the section on Generation Availability in Behind the Meter Generation (found in Chapter 2) to see the setup for modeling DER as an explicit stochastic resource. The difference with current DER technology, however, is the high correlation to irradiance for their availability. With this high correlation, ~~weather~~ weather-related data as demonstrated above could supply another marker into the DER's availability. These types of resources use a mix of demand techniques as seen above and parameters seen in Chapter 2, and as such similar data sources can be expected when modeling the DER in a probabilistic study. As there is no current database or source for availability of DER, a mix of operational data and weather data can be expected to model each state of the stochastic representation.

Data Validation & Cleansing

Once data are formatted across all reporting years, entities should consider performing data reviews and validations, as well as post-processing work if the data are large to ensure the underlying data in question is of sound quality. These validation and cleansing methods are not just relegated to demand data, and are summarized generally in Appendix A.

Demand Reconstruction under Boundary Changes

FERC 714 filings are housed in a central resource so an entity can import the same submitted demand data into the resource adequacy study. This, however, imposes an issue where an entity's boundary changes or is under study in a different boundary. These geographic changes will require some reconstruction of the demand in each area in order to maintain the same level of demand uncertainty across the entire study region. Two options generally exist, a time-series reconstruction or a comparison of the peak demand in each area creating a ratio. The former is more time intensive~~,~~ but provides a greater level of accuracy for the added or reduced demand based on the geographic change. The latter option provides a quicker way to adjust the demand shape in the study~~,~~ but assumes that the peak ratio is valid for all times in the year. This creates a less accurate depiction of the demand change.

Demand Data Requirements

The data requirements for use in resource adequacy studies revolve generally around the time granularity of the data. An hourly representation of demand levels is required for most studies, and associated databases may or may not have such hourly representations. In such instances, hole filling programs and other trend-based algorithms can fill the gaps associated with transferring the data into hourly format. This is crucial as some of the current metrics the PAWG has in their previous reports, the metrics are in hourly format. The reader is reminded that many databases may not have the greatest quality of data; however, such data could be sufficient for their report or study. Such databases simply require the post processing methodologies as discussed in the SERC example in **Figure 1.4**.

Collection methods

There are varieties of both sources and mechanisms for which data can be acquired and utilized for conducting probabilistic assessments. The specific data needed can vary significantly depending on the type of assessment as well as the underlying characteristics of the system under study. Aspects potentially affecting the availability of data include status of local, state, federal regulatory framework, market construct and available operational data, underlying resource mix and trends information, and/or agreements or tariffs with other Registered Entities. For NERC Registered Entities conducting probabilistic assessments, data sources being utilized vary by jurisdiction and applicability to their respective systems. A summary table of the various types of collection sources for different types of entities is found in **Table 1.3**. It is anticipated that other data sources exist for this data, and the table is provided as a start for collecting the type of data.

Table 1.3: Data Collection Notes on Different Entities

Entity Category	Entity	Notes on Data Available
Federal, State, or Provincial level	US Energy Information Administration (EIA)	The EIA contains a lot of valuable information on various energy products, including: LNG export, generation capacity, and an hourly grid monitor. Care must be taken to gather the source of data, or to understand the assumptions associated with the reported charts, graphs, or other tools.
	National Renewable Energy Laboratory (NREL)	The data available contains maps, models, and tools used for energy analysis. Specific ones help with association of data and others are tools to feed probabilistic studies, such as weather data.
	US Census Bureau for US based regions and Statistics Canada for Canadian regions	The data here contain population and census data in particular geographic regions. Additionally, collects and publishes nationally commissioned data on such populations.
	Public Utilities Commissions	These entities can provide state, provincial, or local agency data specific to energy and resource type.
NERC Registered	Generator Owners or Generator Operators (GOs/~~Gops~~GOPs)	Generation entities can report their outage information to the NERC GADS, and in cases where more information is required, can assist in determining their generation availability. The latter is especially true for newer plants.

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Table 1.3: Data Collection Notes on Different Entities		
Entity Category	**Entity**	**Notes on Data Available**
	Distribution Providers (DPs)	These entities provide their distribution system to serve end-use customers. These entities are able to provide information on their served demand
	Transmission Owners (~~Tos~~TOs)	These entities are the owners of equipment for the long distance transmission of power~~,~~ and may be able to provide outage information related to the equipment they own. For example: transmission lines and transformers
Operations/Market	ISO/RTO Capacity Markets	Each ISO/RTO provides an outlook on the anticipated socio-economic changes and some of them provide outputs usable in probabilistic studies

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Chapter 2: Thermal Resources

A large majority of resources in the BPS are thermal resources that convert chemical energy into electrical energy by burning of a fuel. These resources can vary dramatically in construction; however, the focus on data collection for reliability studies is on modeling the availability of the generation and ~~at what~~the ~~predicted~~assumed operating level of that generation~~ is~~. In general, a two state Markov model is the end goal for these types of resources so data collection will center on gathering enough information to fill the model. As other models exist, this section will detail the many sources of filling out any type of stochastic model.

Outage Data

Outages must be considered for all resources in conducting probabilistic assessments as outages have the ability to materially affect the availability of generators to meet the demand. NERC Registered Entities typically utilize a combination of data sources[12] to account for planned and unplanned~~, and forced, and maintenance~~ outages along with their associated uncertainties. These typically include a combination of historical information, performance, and potential correlations to weather data. Some of the types of forms used for the information include generator availability[13] and outage rates (NERC GADS), such as the equivalent forced outage rate, FERC 714 hourly reported data, and market data. In addition, some selected entities utilize a combination of forecasted resource price data, powerflow studies or perform regression analyses for potential correlations with outside datasets.

For thermal resources, the majority of the outage data required to formulate the equivalent forced outage rate will require a data source including parameters for planned outages, maintenance frequency and length, and forced outages, which include repair and failure rates[14]. The parameters associated with the planned outages include the maintenance cycle and length, usually ~~are~~ related to the months of the year (i.e., two of the twelve months) and the length of days associated with that outage. There does exist cases where the planned outages can have durations across years, and such cases will need to assure that the durations are related to yearly outage metrics. In addition to these planned outage inputs, the parameters associated with the forced outages include full outage mean time to repair, full outage mean time to failure, and partial outage deratings for however many derate states there are. For partial outages, the critical component is hours for MW unavailable, no matter the derate type. The sum of the zone is the critical component, then grouping by event type, can be informative for other model or data validation considerations.

> **Key Takeaway:**
> Building the outage rates of thermal resources requires forced, planned, maintenance, and other outage ~~data~~types. A single data source may not have all the types of outages.

The data source for the forced outage rates can be fulfilled in the NERC GADS database; however, that data does not include reported planned outages and is a calendar-reporting database where multi-year events may have differing unique identifiers. To account for those differences, supplemental information is required to bridge the gaps. In an informal poll by PAWG membership at their meetings, many of the companies contain an internal data source that accounts for the planned outage data. Some of these functions are not in the planning departments, but rather in the operational departments. When using operational tools, it is important to remember that the data may need to be altered in order to account for errors ~~occurred~~ incurred while logging the planned maintenance records.

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[12] These data sources may be quite large. For instance, ANL has over 650 million records of customer outage data sampled at about every 15 minutes.

[13] Depending on the generation model, EFOR versus EFORd will demonstrate if the plant was in demand when the outage occurred for use in determining the generation availability. The NERC Performance Analysis Subcommittee has identified that the NERC GADS does not have enough information to calculate the EFORd modeled outages using that data source only. As such, the resource planner needs additional operational data if using this in the model. ~~[POSSIBLE LINK TO A PAPER]~~

[14] These sources for data are used to develop an estimate for the FOR of the unit. IEEE Std. 859-2018 describes the statistical modeling concerns surrounding the use of point estimates or averaging of results as well as the assumption of independent outages across the generation fleet.

Additionally, a Canadian Electrical Association (CEA) reliability database can also provide the statistics regarding thermal outages that aren't related to ~~event based~~event-based performance sources, much like the NERC GADS. In each of these sources, cleansing of the data in order to align the information submitted to the database and aligning it with the records found in operations that take on these derates. This type of cleansing may require knowledge of the model[15] in order to align the transition rates with the submitted and forced conditions.

When utilizing the NERC GADS database, a few other peculiarities exist for thermal units, as the reporting for units may not be consistent across the database. For units with a high startup rate, taking startup outage out of EFOR is a more appropriate way to model the stochastic nature of the unit. Then the resource planner can utilize that reduced EFOR for those units. The startup failure rate may show up as a derate or as an outage rate. An additional consideration exists for NERC GADS. The database is set up for the immediate timeframe, meaning that using it as a data source for derates will only provide the reduction of MW from the current ambient conditions. For some thermal units, this is not an adequate indication of the starting point, as some units are highly sensitive to ambient temperature. For these units, additional data in the form of a temperature curve assists in developing their stochastic model.

For entities that do not use the GADS data, such as the IESO, they have an internal database that ~~takes into account~~considers all outages (submitted, forced, and approved) on a per generator basis. Other entities also maintain an internal central database for this data. Generally, those entities utilize a set of samples from historical databases and submit~~ted~~ planned outages to forecast the generators outage data for the study. This outage data ~~are~~is similar to the planned outage databases discussed above. Similar conditions exist to ensure data accuracy with reporting of planned outages in this type of system as well as the forced outage data. For the IESO, the planned outages are modeled as a part of future planned outages, 10 Year Forms with projected outage schedules, and historical planned outage rates. By collecting the data in one source, IESO is able to model their thermal resources.

Perspectives on Predictive Outage Forecasting

Key Takeaway:
Predictive Outage schedulers provide methods to forecast outages in future years, where the planner conducts the probabilistic resource adequacy study.

Historical Generation Availability Data System (GADS) data collected by NERC is a common and standard data source for entities modeling conventional generation[16]. Operational schedulers can also be a source of this information, and the Control Room Operations Window (CROW) would be another valid data source for predictive outage forecasting. However, access to the information within this database can be challenging and unit specific information is not accessible to all entities[17] . An alternative way to obtain the data is by requesting it from resource entities directly. A specific example for requesting GADS data from resource entities, including the data request notice and data submission form, can be found in Appendix B. Since conventional generation outage trends may change over time, it is useful to predict outages in planning studies. An example of such is in ERCOT, where staff reviewed several predictive algorithms, such as the Prophet[18] tool developed by Facebook, to determine its usefulness in capturing changing trends. A predictive forecast approach based on Prophet[19] has been tested to forecast fleet-wide forced outages. For unit-specific outages used in probabilistic studies, the predictive approach may not be applicable. Based on the ERCOT's experiences with such data sources, the predictive approaches can help visualize the nature of the combined historical and planned outages to provide a way to more accurately collect the correct outage rates to apply to the study. To fuel a stochastic model, these predictive outage-forecasting tools should include mean time to failure, mean time to repair, mean time between failures, and other transitions between the stochastic states to be an effective data source.

[15] Such as the distinction between two-state and multi-state Markov models for thermal resources

[16] These databases log historic outage data to calculate their availability. There are conversations on the use or nonuse of historic data in predictive probabilistic studies found in IEEE Std. 762-2018 and IEEE Std. 859-2018.

[17] Only entities authorized to view unit specific data are allowed access to that data due to the sensitivities surrounding the data.

[18] A link to the tool can be found here

[19] Link for the Prophet tool can be found here

Data Considerations for Capacity Constraints

> **Key Takeaway:**
> Many of the capacity modifications are highly model dependent, indicating the need for varying data source requirements. Data collection should be considered on a case-by-case basis.

Outside of planned and forced generator outages, there are other factors that can also affect supply availability, which must be accounted for in reliability assessments. Factors such as emissions constraints, unit deratings, fuel availability and capacity constraints all limit the availability and ability for supply side resources to meet the demand and can have wide implications for reliability, especially in extenuating weather or stressed system conditions. Additionally, some future market conditions may impact the capacity or dispatch of a unit where such markets affect the operational characteristics of the thermal generation resource. Some of these constraints can be found in the source documents that dictate the market rules, or in the regulatory body that imposed the rules in the present or future market.

Emissions Constraints

Entities must account for the potential application of emissions if they plan to model these constraints in their resource adequacy studies. Some of these constraints are ~~taken into account~~considered during economic dispatch of the units, while other models require explicit states modeled based upon the study conditions. Much of these constraints are regulated by different government agencies, and as such, they are generally unique in each area. In general, the assumption for emissions is that during blackout or resource inadequate periods the regulators will lift the constraint; however, these constraints can be adjusted by modeling the outage rates, capacity limits, and other water flow constraints in order to model the impact these policies have on specific generators. However, since the modeling varies, the amount of data required will vary as well. Resource planners are suggested to look to government agencies or emissions regulators in order to gather enough information to model the emissions constraints.

Fuel Availability Data

The NERC Electric-Gas Working Group (EGWG) has helped determine the interfaces and potential interdependencies that the electricity sector has with the gas pipelines and potential disruptions of those pipelines[20]. As it pertains to resource adequacy, the data required to model the impact of pipelines can be cumbersome and is not available in NERC GADS. The data source selected should consider mean time to failure and mean time to repair rates associated with those operating states. These general considerations are typically accounted for using Equivalent Forced Outage Duration (EFORd) in some regions, but others do not account for this in the EFORd as that measure is typically reserved for mechanical outages. Similarly, the fuel availability statistics will need to account for the derate associated with lack of fuel. Due to these complexities, capturing this in a probabilistic study is very cumbersome and will require more than usual amounts of data to perform a study. A resource planner will require access to pipeline outages and other gas information systems in order to model the impact on a resource adequacy study. In some very restrictive areas for fuel availability, a resource planner can consider modeling this thermal resource as an energy limited resource with considering some aspects of other energy limited resources in Chapter 3. In particular, the available natural gas, in MBTU[21] per day, from a data source in these scarce periods is important to consider.

[20] Link to EGWG report here

[21] This is a common measurement in the natural gas industry to indicate 1,000 British Thermal Units (BTUs)

Capacity Modification on Ambient Conditions

> **Key Takeaway:**
> Thermal power curves allow the study to adjust the capacity based on the ambient temperature studied. Modeling ambient conditions also requires weather data close to the resource

To capture the capacity modifications due to differing ambient temperatures, some entities send a survey to their Generator Owners with capacities at specific temperature points. These points provide a curve, and that particular curve is used to set the capacity derates under the ambient conditions; the source of those ambient temperatures is the same as the ~~Weather~~ Weather-Related LFU portion discussed in Chapter 1. The combination of these two provides a simplified method to model correlations between the weather and generator outputs for the forecasted short-term; nevertheless, the source for these model considerations stays the same: a survey to generator owners to generate a thermal curve and the ~~weather~~ weather-related LFU sources.

Other capacity modifications depending on the ambient conditions exist. Terms like High Sustainability Limit, which ERCOT defined as the real time maximum sustained energy production of a resource; Dependable Maximum Net Capacity, which is defined as the maximum power a resource can supply under specific conditions for a given time interval without exceeding thermal or other stress violations; and Seasonal Capacity, which is the capacity of a resource in a given season, come into play. These terms all try to describe the energy restrictions on ambient conditions and constraints that would hinder the modeled generator in the reliability study from producing its nameplate value. Should this be a major concern in the study, the data source[22] chosen should be equipped to handle the desired study conditions and gather enough data on the constraint to model it stochastically. At minimum, this means determining the mean values for transitioning between the states.

Generation Availability in BTM Generation

Data sources for behind the meter generation will be highly model dependent, but there are a few considerations for these generators, which typically do not report in surveys or other generator data sources. These types of resources sometimes can be found as a load modifier, but those resources can sometimes be sensitive to a market price ~~of~~ or other dispatch signals, and are thus not related to the electrical characteristics at their Point of Interconnection (POI). To gather enough data on these types of resources, a case-by-case data structure will most likely be needed or a wide swath of assumptions to be made based on the available data to the resource planner. Two approaches exist for these generators. One is to net them against the load ~~where~~ to which they are close geographically, which carries all the assumptions of demand modeling. The other is to model these as discrete stochastic resources, with a recommendation for a simple two state Markov model that can be developed off operational data superimposed on other time-synchronized measurements to determine the resource's full capacity. If modeling via the latter method, the same data types outlined in this Chapter are expected to be placed into the model, and as such similar data are to be collected. Collecting this type of data may be cumbersome for these types of generators, so heuristics developed off knowledge of these facilities can aid in determining when to collect the data to best model the resource.

[22] This may be a survey to the GO, as the IESO example above demonstrates

Chapter 3: Energy Limited Resources

Some of the common resource adequacy discussions are based around a discussion on the capacity of resources and the availability of those resources to meet the level of demand in a study. In the case of energy limited resources, such as hydro, wind and solar, capacity related discussions are only one facet of reliability planning. This chapter focuses on the different types of energy limited resources to describe how to collect data representative of them for use in a probabilistic study.

Hydro Units

The vast majority of hydro generating facilities are considered as energy limited units since these facilities are dependent on the availability of water resource. The time constant for the availability of water may be longer than that of wind or solar. The effect of unit-forced unavailability is not significant on hydro generating system reliability; therefore, many resource planners incorporate this unavailability in estimates of energy limitations when conducting probabilistic analysis. Some of the input parameters for each hydro power plant are:

- Installed/in-service, Planned and retirement dates
- Monthly maximum and minimum output of each plant
- Monthly available energy from each plant
- Energy distribution (available energy to hydro unit)
- Forced Outage Rate (FOR) or EFORd

For hydro generating facilities, some entities may assume that the available water or fuel for each plant has little or no uncertainty, or that the water resource is in a drought condition. This is a conservative approach to ensure that sufficient resources will be available when needed. However, if the uncertainty is to be modeled, the data needed to incorporate that into the hydro facilities model requires similar data to other weather-related energy limited resources.

Simulated Solar Generation

In a loss-of-load probabilistic study, it is important to cover all of the weather years of data for resources highly correlated to weather data (e.g. Solar PV). In order to do so, resoruce planners can simulate the expected behavior of the solar plant for use in their loss-of-load probabilistic studies, and many tools are available to augment or replace observed historical generation data for a particular resource or neighboring resources. One such tool is the Weather Research and Forecasting (WRF) model[23] used to generate the historical atmospheric variables such as wind speed, temperature and irradiance (as well as snow, ice, or other ground cover), which in turn simulate solar power production at each location in the model. The most important data points to produce a simulated solar profile are the types of arrays, soiling, shade, snow or ice cover, and control parameters associated with tracking the solar bodies. Some tools that utilize these parameters to then convert into AC capacity are the NREL SAM tool[24] ~~or the Waterloo tool[25],~~ with the former inputting parameters to produce the profile and the latter producing profiles off generic adjustments. The latter takes into account multi-order variables when producing the curves, but requires additional site-specific data

Key Takeaway:
Simulated profiles can be performed for both existing and planned solar PV sites. In either case, site-specific details help refine the fidelity of the profile. Some tools provide DC capacity and others AC capacity. For use in resource adequacy studies or assessments, an AC capacity will need to be calculated if the tool does not do so.

Commented [JS19]: Does this translate to Forced (or Unplanned) Outage?

Commented [JS20R19]: Yes, this does translate to "Forced Outage" in some studies. Some hydro facilities availability is dominated by the water availability, others from the unit components.

Commented [JS21]: Simulations should also include snow or ice cover.

Commented [JS22R21]: Added snow or ice cover to relevant sections.

Commented [JS23]: From David Jacobson: "Needs a reference"

Commented [JS24R23]: Deleted the reference.

[23] Information on this model is available here
[24] Available here. See information on the PVWatts portion of the tool
~~[25] Available here. JP NEEDS ASSISTANCE FINDING THIS ONE!~~

that may not be available when conducting a resource adequacy study; however, it still remains an option for more specific profiles.

To walk through the process, ERCOT computed the atmospheric values and adjusted them using surface station data and input them into a proprietary PV model to produce the hourly power output profiles. Programs mentioned above would also provide a profile, but ERCOT utilized proprietary models to accomplish the goal, yet another option available to resource planners. More details about developing hourly solar power profiles can be found in the solar profile methodology report, available on ERCOT's Resource Adequacy webpage[26].

If utilizing site-specific information to inform profiles, data found in **Table 3.1** is useful in providing to a program or vender when gathering simulated solar profiles. Some of the information is expected to be assumed, as some can be site-specific and many of those parameters are not available at the time of study.

Table 3.1: Solar Profile Data Requirements

Category	Data Point	What to Gather
Static Plant Details	Installed Plant Capacity	DC MW Capacity
	Tracking System Type	Fixed, Single, or Dual Axis
	Tracking Origination	Azimuth, north-south, other
	Module Tilt	Horizontal, Tilt to Latitude, other
	Module Azimuth	Degrees off Azimuth
	Ground Cover Ratio	Ratio of array coverage by other arrays
DC to AC Conversation	DC to AC Ratio	Efficiency of DC to AC conversion in MW
Inverter Details	Inverter Capacity	Either 1) Inverter make and model, or 2) Number of Inverters and the inverter capacity
PV Module Details	Module Capacity	Either 1) Module make and model, or 2) Number of Modules per string and the module capacity

Key Takeaway:
Public resources exist to generate the simulated solar profile; however, non-public options exist for use as well.

Site-specific parameters are not required for these profiles; however, they provide a more granular approach to modeling the contributions of solar resources. In general, the solar profile is a time series of data on the total power production (in MW) at a solar facility. Two methods exist for this. One is to gather time-series irradiance data and convert it to MW by collecting efficiency of the solar facility to convert that irradiance into MW. This conversion acts as the solar profile for a particular resource and the NREL database for US entities contains many years of solar data for this purpose. Canadian regions can somewhat be covered by that database, but meteorological data from weather stations may be able to supplement this. The other method is to take historical generation samples from another solar generation facility, gather irradiance data as above, and then merge the two in order to capture some other uncertainties not related to irradiance. Some entities use a solar

[26] http://www.ercot.com/content/wcm/lists/114800/ERCOT_Solar_SiteScreenHrlyProfiles_Jan2017.pdf

forecaster to accomplish this task, but many others do this merge of data inside their own company. This latter method allows site-specific information that is not necessarily the information as detailed in **Table 3.1**, but captures the effects of that table.

Hydro, Wind and Solar Data

Hydroelectric, wind and solar resources are similar in that their production at a given point in time is governed by fuel availability. Hydroelectric resources have varying levels of control over their availability depending on the site; run-of-river generators are entirely dependent on river inflows, while generators with large reservoirs can have daily, weekly, seasonal or even annual storage. The goal of any data collection for modeling the capability of these resources is to find data that give the best representation of the capability of these resources over a period.

For all three resources, there are two basic types of data that can be collected: production data and fuel availability data. At a high level, production data captures the amount of electricity generated over a given period, while fuel availability data captures the amount of primary energy that could have been converted into electricity over a period. For all three resources, the collection of production data is the same, assuming full data availability. For many embedded generators, production data may not be available. Data that can be collected that captures the amount of primary energy that could have been converted into electricity for each resource type is outlined below.

When gathering data for these units, take care to ensure that the same historical time frame is used for the demand sampling. If a different historical year is excluded in the sampling for data in the solar resource, the cross correlation coefficients of the hydro, wind, or solar resource with the demand will impact the end probabilistic metrics in the study. Maintaining the same historical time period as the demand sampling will alleviate the concern over these cross correlations or any other dependency between the resource availability and demand. A good way to think about this is that in times of high irradiance, many air conditioning loads are likely to be active at a given time. If a TP samples irradiance outside of the same time boundaries as the load, the correlations in the shapes need to be described; otherwise, they may be misrepresented in the study.

Key Takeaway:
Energy limited resource data gathering should have the same timeframe as the demand collection in the resource adequacy study.

Solar Fuel Availability Data

For installed solar PV plants, the same irradiance data that created a solar profile can act as a fuel availability curve for that resource. There are various methods to collect irradiance data, with some sources detailed above. A cloud cover or satellite analysis might be necessary to fully determine how those impact the availability of the solar resource to contribute in the resource adequacy study. Some models ask for a temperature and wind speed aspect for solar availability, and any public~~al~~ly available data source or nearby weather station can have those measurements. In addition to Table 3.1, some models require the Global Horizontal Irradiance (GHI), Diffuse Horizontal Irradiance (DHI), or Direct Normal Irradiance (DNI) or some combination of the three in order to calculate the output of the solar facility. Regarding those values, some weather stations are not equipped to measure all of the values.

Wind Fuel Availability Data

Wind fuel availability is similarly ~~build~~ calculated as the solar fuel availability. However, since wind speed is dependent upon the height of the measurement, the turbine height needs to be accounted for in the gathering of wind speed. The historical wind generation in that area is important ~~to obtain~~ in order to get the distribution of wind speeds and thus the generation of that facility. For operational plants, many have wind speed recorders that can be obtained ~~in order~~ to build the curve. NREL also maintains records for wind speeds between the years of 2012 and 2015; however, recent years are not recorded. NOAA can provide the wind speed for these and other years to

Key Takeaway:
If historical generation records are unavailable for the resource, geographically close profiles are adequate. This includes weather stations.

supplement the data from NREL. If the operational plant does not record their data, close by weather stations are also acceptable to get the data from. A power curve translates this wind speed curve into a total MW output of the wind facility in order to be used in the study. Other weather data may be required based on the sophistication of the wind model in the resource adequacy study.

For future looking resource adequacy studies, the assumption of geographically close data availability is not always a good assumption. One tactic is to collect ~~g~~ the capacity of the facility based on the projected design to assist in ascertaining the availability of the wind resource. The key parameters to procure are the design parameters and associate the parameters to an expected wind MW curve. Design factors to consider include ~~are~~ turbine height, cut-in speed, cut-out speed, and other speed breakpoints as well as hot or cold temperature limitations and ice-loading capability of the turbine as based upon the design. As an example, WECC samples historical wind generation from their nameplate and uses that profile at a different wind generation facility in order to supply the wind speed curves. Then any design constraints are applied to that profile to gain the total MW production curve from that resource. In general, for studies that are modeling future wind facilities, a profile of wind speeds from other facilities or meteorological stations along with design parameters from the resource developer can produce the expected MW profile of the wind facility. This process is very similar to the simulated solar PV section above.

Commented [JS25]: Hot and cold temperature limitations should be considered, as well as ice-loading on the turbine blades.

Commented [JS26R25]: Added these parameters to the design factors. Additionally changed list to be unbounded of the design factors to consider.

~~In some instances, wind production reaches a point where transmission operators or generator owners must curtail the wind to meet plant or system condition constraints. In such instances, similar derating methods are required from the thermal resources. The conditions surrounding the derate should be recorded and the constraints modeled when using the wind resource in the resource adequacy study.~~

Commented [JS27]: Wouldn't this be true for all resource types? I would expect system constraints to be captured in the transmission model. Site-specific constraints should be captured in the MW production curve.

Commented [JS28R27]: Deleted as the sentences were speaking to operational characteristics (or modeled system conditions) opposed to fuel availability (adjusting the MW production curve)

Hydroelectric Data

Similar to the wind data, representing energy-limited hydro facilities in the study could require a translation of their water supply into a total energy production. To do so, the resource planner will consider hydrologic or fluvial conditions such as water inflow, outflow, and head of the hydroelectric resource. If using flow data, a power curve is required to translate the water flow into a time series MW on that resource. For these types of facilities, many regulations dictate the amount of water stored or required to be flowing across the facility, so data on spilled water can supplement production data to give a better indication of the availability of the resource to produce electricity in the study. Additionally, only using production data underestimates the potential of the hydro resource. Offer data can supplement the production data to get the energy, operating reserve, or both to express the capability of the unit, as the total capacity of the unit is the current capacity of the resource is the operating reserve the unit is providing added to any current power production. Since hydro facilities have many moving parts, planned and forced outages are also a concern, albeit a lesser concern. Other outages for hydroelectric facilities can also include environmental or safety outages, which have a similar lesser concern in terms of modeling in the resource adequacy study. See Chapter 2 on Thermal resources to find databases that these facilities can report to on outages.

The end goal of data gathering for hydroelectric resources is to build a water year for the amount of water available for the plant to use in generation of electricity and to incorporate any environmental factors, operating restrictions, and generation availability that may limit production based on the sophistication of the model. Unlike other energy-limited resources, more attention can be made to the environmental factors that dictate the amount of flow out of the plant that will describe the availability of the resource. Additionally, if the hydro facility is a run-of-river facility, the inflow of the river and environmental constraints will likely dictate the availability of the plant. Some data sources for the data are Environment Canada, NOAA, and other national weather databases that measure hydrological quality.

Energy Storage Systems

As of this report, two major types of energy storage exist: battery energy storage systems (BESS) or pumped hydro storage. The inputs in **Table 3.2** are important to model energy storage systems. Not all parameters are exclusive to pumped energy storage systems or BESS, though many parameters cross over.

Table 3.2: Energy Storage System Profile Data Requirements		
Category	**Data Point**	**What to Gather**
Resource Characteristics	Maximum Generating Capacity	The maximum MW the facility can generate when discharging its energy
	Minimum Generating Capacity	The minimum MW the facility can generate when discharging its energy
	Maximum Charging Capacity	The maximum MW the facility can take on when charging its energy supply
	Minimum Charging Capacity	The minimum MW the facility can take on when charging its energy supply
	Dispatch Order	Position in the economically constrained dispatch[27]
	Storage Cycle Efficiency	Total Roundtrip efficiency on the charge or discharge cycles.
	Maximum Energy	Pumped Storage Reservoir or BESS maximum energy storage[28]
Outage and Maintenance Data	Historical Outage Data	Time series MW production and consumption for many historical years
	Maintenance Periods	Time windows where the resource is under outage for maintenance.
	Availability of the Unit	Failure and repair rates of the unit.[29]
Unit Availability during Ancillary Services*	Pumping Operation	Similar to the Outage and Maintenance Data
	Normal Operation	Similar to the Outage and Maintenance Data

*This type of data may be very difficult to obtain for battery energy storage systems as they may have many different ancillary services. An operational profile may be more informative.

Key Takeaway:
Understanding the energy storage device's operational characteristics allows for adequate modeling, and informs the data collection and databases required for the study.

Initial additions of energy storage systems to systems that are capacity constrained rather than energy constrained are generally capable of providing full capacity value with 4 to 6 hours of continuous operation relative to conventional resources. As an example, an energy storage resource can be charged during low load periods and dispatched during the few highest load hours of the day or by other dispatch patterns depending on how the resource is procured. However, when the penetration increases above 2 to 3 percent of system peak, rigorous modeling of all constraints and capabilities of energy storage systems is required. While the dispatch methodology is still the same, the frequency and duration of

[27] This is important for Emergency Operating Procedures or other Ancillary Service capacities these storage systems supply. Market data may be required

[28] In pumped hydro cases, this maximum may be quite large.

[29] In BESS systems, this is highly crucial due to the construction of the battery pack. Other energy limited resources have resilient measures in place; however, BESS construction has either a "all or none" capacity.

high load~~s~~ becomes more binding on the capacity value that energy storage resources can provide since they are required to serve more of the load.

It is also important to note that there are numerous possible interactions of the various energy storage specific inputs. For example, if the dispatch order of energy storage systems is not optimized for reliability, they may need significantly longer duration capability to provide full capacity value. In addition, if energy storage resources can be used to serve ancillary services, their reliability value can be substantial with even shorter duration capability.

Chapter 4: Emergency Operating Procedures

Emergency Operating Procedures (EOPs) are control actions or tools that system operators can utilize to modify generation or loads under stressed, abnormal or emergency system conditions. These conditions could be resource supply or reserve deficiencies, or element contingencies under the course of BPS operations. EOPs should be properly accounted for and modeled into probabilistic reliability assessments to ensure that a realistic representation of system risk concerning resource adequacy are considered. These tools can be invoked or implemented to mitigate possible resource shortages or emergencies prior to the disconnection of load and the likelihoods of use and amount of relief can vary. The procedures and details of EOPs is widely dependent on a Regional, Area or entity basis and typically occurs under pre-established criteria.

Parameters

Modeling these types of ~~resources~~ remedial actions can vary greatly by entity and data sources can vary accordingly. EOPs generally, however, will provide a means to relieve a constraint for a specific amount of time. Some types of EOP's that could be considered for studies include:

- Interruption of Transmission Service (Transmission Loading Relief)
- Load Curtailments or Interruptible Load Programs;
- Operating Reserves;
- Use of import agreements with neighboring systems;
- Voltage Reduction;
- Special Resources;
- Demand Response;
- Public Appeals;
- Or, cyclic load shedding.

These types of procedures can have specific parameters that must be considered in modeling. These could include the number of times in a given time period the EOP/resource can be performed, duration and time period between calls, and the amount of relief on subsequent calls or fatigue factors. These constraints can be seasonally adjusted as well depending on the area as seasonal temperatures may prevent an EOP from being enacted on the demand side from a non-disturbed system. With regard to these procedures, state governments or programs may have the details on the limitations and can help to associate the exact parameters required to model that specific type of EOP.

Collection Methods

> **Key Takeaway:**
> Emergency Operations Procedures require less data gathering to model than the other topics discussed due to their fixed duration and frequency of calls.

Due to the rigidity for some EOPs, the duration and frequency are generally fixed indicating a lack of major data collection efforts being needed for a probabilistic study. In terms of data collection, some programs may require a customer to sign up with the utility for the program. As such, for those programs the repository that holds those records will be the source of data for the probabilistic study to determine how much load is relieved when the EOP is enacted. Relevant load relief data (in MW) for EOPs can be determined through several methods depending on the system; however, the majority are based on collection via source documentation or by historical availability.

Commented [JS29]: From Robert Reinmmuller:
"Emergency Operating Procedures (EOPs) are control actions and tools for system operators to utilize under emergency conditions. The use of these tools as resources is not advisable in the planning framework and the inclusion may not be appropriate for the probabilistic reliability assessment. The emergency actions are only considered during the operating horizon and should not be included in planning time frame assessments to avoid a compounding effect."

Commented [JS30R29]: PAWG agrees that EOPs are actions to use under emergency conditions, which are incorporated in many probabilistic studies. Probabilistic studies can model the future condition as if the current available procedures were available in order to assess the reliability in emergency situations in those studies. Furthermore, other reasons to model EOPs in probabilistic studies is to qualify the effect the procedures have to mitigate reliability risks as a scenario or for other regional uses.

Commented [JS31]: TPL-001 does not allow curtailment of load or Firm Transmission Service for certain outage categories (e.g. P1)

Commented [JS32R31]: Agreed. TPL-001 however, is not the basis for producing probabilistic resource adequacy assessments. A TPL-001 planning assessment covers steady-state, stability, and short circuit studies in the planning horizon. A resource adequacy study has a different objective.

The source documentation methods look at the establishing papers, legislation, or programs that dictate how EOPs will be called upon and use such information as data for study. For instance, some EOPs such as voltage reduction can be determined through the source documents of those schemes. Other EOPs' load relief data can be collected through the registration of resources and the availability requirements for these resources in an emergency. Even further, some EOPs are spelled out in the tariffs, and serve as a good data source for determining the amount of available capacity for load relief. Limitations on number of calls for these EOPs need be considered when collecting the data as well as looking at the assumptions surrounding the source documents to see if both still hold for the study in question. This type of data may not be found in the source documents and should be considered when collecting data for study.

Regarding historical availability methods, the resource planner can also actively collect data regarding how much relief occurred from historical calls to EOPs. Trends could be also reviewed from GADS or other measured data to develop reasonable assumptions for usages for a given EOP if the other methods cannot provide the data. Availability of these resources at the time of the emergency, such as the proportionality to peak loads should be considered when developing assumptions utilizing the availability databases.

Physical Testing or Audits for Voltage Reduction

If physical test are available to the planner, the resource planner can commission a voltage reduction test and utilize those results to determine the amount of relief that the EOP can provide in the probabilistic study. These tests may require other jurisdictional approval prior to conducting the test. Other types of tests may also exist to provide the estimated capacity relief from other EOPs ~~can provide~~ and entities can look to either producing their own test or coordinating with other entities to produce a test.

Chapter 5: Transmission Representation

More and more attention has been given to consider transmission constraints in probabilistic resource adequacy assessment. There are many different parameters associated with transmission lines, and depending on the study, not all of those parameters may be useful in determining the interconnected system's reliability in a probabilistic representation. A majority of the data sources discussed in the other chapters are representative of the desire to determine if sufficient generation is available to meet demand. Similarly, there may be a desire to determine if sufficient transmission is available to ~~meet demand~~deliver that generation to meet demand.~~.~~

Key Takeaway:
Data requirements depend on the types of transmission model used in the resource adequacy study. Some require additional line parameters, but others require only transfer limits

Interface Limit and Detailed Circuit Representation – Data Requirements

Typically, there are two different ways to represent transmission constraints: interface limit model and detailed circuit representation. In the interface limit model, the transmission is modeled as a "pipe" between two areas with specific constraints and properties. In the detailed circuit representation, the transmission is modeled using all transmission lines that may be seen in positive sequence load flow software into the reliability assessment realm. These types of representations can be useful depending on the type of study being done; however, their data sources may not always be the same.

Commented [JS33]: In the "pipe" model, only the Firm transfer limit between areas should be modeled for Resource Adequacy studies. If the more detailed transmission model is used, then (n-1) contingency analysis would identified this limit.

Commented [JS34R33]: No changes were made based on this comment. The PAWG believes that the resource planner needs to make a modeling decision on the transmission service and how to populate this information in the model. Many assumptions exist on what should be in the "pipe", and PAWG asserts these assumptions should be clear for each particular study. Furthermore, depending on the study, these limits can change on time frame, temperature, and many other variables.

Interface Limit Model

The transmission constraints between areas are modeled with interface transfer limits. Each interface is represented as a tie line with bidirectional transfer limits. Physically, each interface may consist of two or more transmission lines and the interface limits and equivalent admittances are typically determined based on thorough steady state and/or transient stability analyses. Most of the existing tools for resource adequacy assessment are able to simulate random forced outages on the interface between areas. The minimum data required for representing the interface limits depending on the purpose of assessment and the method employed for network flow analysis. **Table 5.1** shows the minimum data requirements for using the Interface Limit Model to incorporate transmission constraints in resource adequacy assessment. NERC TADS is a database that records the type of outages associated with transmission lines and provides enough information to formulate a forced outage rate for the transmission elements. Aggregation techniques will be required to associate the specific line data with how the transmission is modeled as the records in TADS may be more specific than the tie line representation. In order to find the bidirectional transfer limits, generally an Available Transfer Capacity (ATC) study can inform on the limiting conditions and the results of that study will provide a "source to sink" capacity between areas, which is very conducive to modeling these interfaces. If adding in the DC powerflow capabilities of load flow software, the equivalent reactance between the source and sink in that ATC study will need to be determined and provided. This may not always be provided in a single ATC study, so model reduction of the powerflow data collected for Interconnection-wide base cases created under NERC MOD-032[30] can aid in finding the equivalent reactance of the interface.

Table 5.1: Minimum Data Requirements (Interface Limit)

Network Flow Method	Import/Export Limit	Equivalent Reactance	FOR
Transportation Model	Yes	No	Maybe
DC Power Flow	Yes	Yes	Maybe

[30] NERC MOD-032 can be found here

Detailed Circuit Representation

Normally detailed transmission models are not required in resource adequacy assessment. If detailed circuits are modeled with generation facilities, the evaluation is often referred to as composite system reliability assessment and a vast number of input data are needed for such assessment. Composite system reliability assessment mainly involves the selection of possible system states for evaluation and the assessment of the consequences of these states. Two basic methodologies are used in the system state selection in composite system reliability assessment. These are analytical contingency enumeration approach and Monte Carlo simulation method. The system analysis in assessing the consequences of selected outage states is the same for both analytical and Monte Carlo simulation methods. AC or DC power flow is employed to determine if a particular state is a success or a failure in composite system reliability evaluations.

The detailed power flow data for composite system reliability assessment typically contains information on the system topology, equipment ratings and various potential operating conditions for example summer/winter, peak/light load, drought/wet ~~water~~ or export/import scenarios. These power flow data are maintained and updated by industry regularly. Outage statistics data such as the failure rate and average outage duration for all of the composite system facilities are ~~required~~ recorded and available from NERC GADS and TADS systems for generation facilities and transmission facilities. Some system specific data such as remedial action schemes for example fast runback of HVDC, normal operating procedures, tapped transmission lines and common mode outage information may be needed. The general procedure and the minimum data requirements for composite generation and transmission reliability assessments are available in existing literature[31].

[31] Billinton, R., 1969. Composite system reliability evaluation. IEEE Transactions on Power Apparatus and Systems, (4), pp.276-281.
Billinton, R. and Wenyuan, L., 1991, July. Composite system reliability assessment using a Monte Carlo approach. In 1991 Third International Conference on Probabilistic Methods Applied to Electric Power Systems (pp. 53-57). IET.
Ubeda, J.R. and Allan, R.N., 1992, March. Sequential simulation applied to composite system reliability evaluation. In IEE Proceedings C (Generation, Transmission and Distribution) (Vol. 139, No. 2, pp. 81-86). IET Digital Library.

Chapter 6: Concluding Remarks

Based on the current methods for setting up a probabilistic resource adequacy assessment, the PAWG identified a few commonalities that are of particular importance. While different studies may require additional data if they wish to study the impacts of a particular risk, for instance cyber-related attacks, the document provides different collection experiences and highlights the key points of resource adequacy studies. In particular, the PAWG identified a few common practices that should be emphasized. In general, the probabilistic studies require large quantities of data to add more complexity to the models in their assessments[32].

The Need for Data in Probabilistic Studies

In general, a resource planner's job is to predict and determine the level of risk for future years. They require a set of predictive models that they develop and maintain. In order to develop and maintain their models, they require access to a variety of different types of data that may not be generally made available. This particular point is crucial, as sometimes engineering judgement is able to fill where data is not available; however, judgement is not a substitute for high quality data sources that are representative of the equipment being modeled. This need for high quality data applies to all the different categories of data in the previous Chapters and is not relegated to demand, generation, transmission, etc. Additionally, the study objective may change the modeled parameters based on the engineering judgement of the resource planner. In any two given studies, certain resources or aspects of a resource may not be a necessary modeling requirement due to the study objective. The resource planner needs to determine the model complexity required for the loss-of-load probabilistic study and use the data sources appropriately to complete the model.

Common Key Points

The PAWG identified the following key points in data collection across many different portions of a probabilistic resource adequacy study:

- Collection of weather data and any portion of the resource adequacy study related to weather should have the samples taken in the same period. If samples are not able to coincide, a cross-correlation calculation can help reorient when the weather data sample was taken and when, for instance, the demand sample was taken.
- When utilizing GADS or other historical outage reporting data, the thermal resources future outage rate may not be indicative of this historic metric especially when the facility moves to different operational characteristics.
- Battery energy storage systems (BESS) can be modeled similarly to other energy-limited resources such as pumped hydro when performing a resource adequacy assessment, with an emphasis on understanding the operational characteristics of the BESS.
- Data collection for transmission systems in probabilistic resource adequacy assessments depends on how detailed of a transmission model is represented in the study. This is over and above the normal dependency that other portions of a probabilistic resource adequacy study.
- Planning Coordinators, Transmission Planners, and other modelers require access to detailed information in order to build and maintain their models for use in probabilistic studies.

Possible Future Work

As probabilistic resource adequacy studies develop and mature, the PAWG recommends that the ERO review this data collection document. By doing so, this document can be utilized along with other probabilistic resource adequacy

[32] This assumes that no assumptions will be made regarding the effect these new facets of the model have on the availability or performance of the element in the resource adequacy study.

documents to assist ~~with~~ entities with developing new probabilistic requirements or improving previous ones. Additionally, the PAWG found the following recommendations:

- When utilizing Generation Availability Data System (GADS) or other historical outage reporting databases, the thermal resources future outage rate may not be adequately represented by use of this historic data, especially when the facility moves to different operational characteristics. A thorough review should be done before using historic outage data when representing future risk.
- Planning Coordinators, Transmission Planners, and other entities should work to gain access to data not otherwise made available that may affect the results of their resource adequacy studies or assumptions. Some entities do not have access to data sets to feed their models, and the need for more accurate studies may require access to data outside of those public~~al~~ly available. This is paramount as resource planners are not able to perform studies without well-developed models, which require a wide range of data.
- Careful understanding of data source assumptions and restrictions should be used when vetting a new or previous data source.

Appendix A: Overview of General Data Management

In general, data used for study should be complete, of high quality, and representative of the equipment under study. As with many other modeling issues, there are times when the data is not always complete, does not follow the guidelines for data submission in the database, or is not accessible without supplemental agreements. This appendix covers some of the general considerations for vetting the data for use in the probabilistic study.

Keeping Data Aligned

When the resource planner is merging many different sources of data or when dealing with large data sets, a few common procedures should be followed. Considering much of the data in probabilistic studies is based on a time series, or has a time dependence (such as weather years), many of the processes deal with this type of alignment. Some general data alignment techniques for entities to consider are listed below:

- Convert to a common time zone, including considerations for daylight savings time changes (if applicable).
- Utilize hourly trends to fill gaps in data, such as zeros and/or blank hourly values due to time zone conversions. These gaps should not be large in size, nor should they be frequent in the data source[33].
- Detect unit outliers in minimum and maximum daily, monthly, and annual peaks for possible data errors.
- Determine the per-unit relationships between hourly values and the daily peaks throughout the years in order to detect anomalies.
- Conduct benchmarking to similar data sets such as, but not limited to, entity reported actual summer and winter peak demands for use in Regional Reliability Assessments[34]

Common Sense Validation Checks

Additionally, there are a few other common sense checks~~check~~ when preparing the data for use in a probabilistic study. This list is provided as an example, and other checks or metrics may exist for determining how trustworthy the data source is for providing information in a resource adequacy study. Examples of such checks are found in **Figure A.1**.

[33] For example, some data sets are not usable with more than five percent total data missing or when the largest gap of data is longer than 12 hours. These values will change depending on the data. In general, a resource adequacy study can fill these gaps; however, these two metrics should be considered when vetting a data source.
[34] A common NERC approach for determining load forecast uncertainty uses the variance in year-over-year deltas of actual peak demand. For this reason, a good sanity check is to compare these deltas from FERC 714 for particular entity or area with that of another data set.

Peak Data

- Correctly filled out field
- Correct mangitude
- Correct units

Energy Data

- Correctly filled out field
- Correct mangitude
- Correct units

Load Growth

- Reason provided for growth exceeding +/- 1%

Resources

- Resource in the right Zone, Balancing Authority, and Organization
- Unit Type matches with fuel (e.g. PV unit with secondary battery incorrectly labeled as a gas turbine)
- No negative or zero capacities for nameplate or seasonal capacities
- Status Code, NERC Class Code, and WECC Class Code are consistent
- No duplicate resources

Reserves

- No blank or null values provided
- Data is consistent with other portions

Hourly Data (Demand, Hydro, Wind, Solar)

- Plotted data do not contain gaps
- Plotted data are consistent with request
- Plotted data demonstrate no abnormalities (e.g. jump discontinuities of large magnitude)

Transmission

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Transformer

- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Peak Data
- Correctly filled out field
- Correct mangitude
- Correct units

Energy Data
- Correctly filled out field
- Correct mangitude
- Correct units

Load Growth
- Reason provided for growth exceeding +/- 1%

Resources
- Resource in the right Zone, Balancing Authority, and Organization
- Unit Type matches with fuel (e.g. PV unit with secondary battery incorrectly labeled as a gas turbine)
- No negative or zero capacities for nameplate or seasonal capacities
- Status Code, NERC Class Code, and WECC Class Code are consistent
- No duplicate resources

Reserves
- No blank or null values provided
- Data is consistent with other portions

Hourly Data (Demand, Hydro, Wind, Solar)
- Plotted data do not contain gaps
- Plotted data are consistent with request
- Plotted data demonstrate no abnormalities (e.g. jump discontinuities of large magnitude)

Transmission
- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Trasnformer
- Line type should be overhead, underground, or submerged.
- Reactances are consistent with design (e.g. X/R ratio)
- Line information consistent in lines with many taps

Figure A.1: Common Sense Checks for Data Validation

Data Retention for Future Studies

Due to the large set of data required to gather for modeling resources in a resource adequacy study, it is preferable to store much of the data for use in future studies. For instance, the transmission system representation, once built, does not need to request the same level of information at each time the model is updated; a notification of which elements, interfaces, or other equipment that have changes suffices. Additionally, outage data do not need to always be collected for the same period. The collection effort should be focused on the data that would supplement what has historically been collected. Because of these, a data maintainer should be used to ensure that the data are not lost, mutated, or ~~in~~ otherwise changed between studies. Additionally, some data ~~are able~~can ~~to~~ be used for different studies, further increasing the value of retaining large sets of data for probabilistic reliability studies.

Appendix B: Example GADS Data Request Example Forms

This Appendix serves as an example, data forms when requesting GADS data from other entities. ERCOT has graciously provided the following two forms ~~in order~~ to provide clarity on some of the information in the chapters.

GADS Data Request Notice

The following information is contained in ERCOT's GADS Data Request Notice and an example data, the form they send to other entities to request data that accompanies the notice. All content provided is to be used as an example for these requests and should be used only where appropriate.

NOTICE DATE: January 31, 2020

NOTICE TYPE: W-X013118-01 Operations

SHORT DESCRIPTION: Requested data for the Planning Reserve Study

INTENDED AUDIENCE: Resource entities

DAY AFFECTED: April 1, 2020

LONG DESCRIPTION: ERCOT is conducting a capacity planning reserve study in 2020 that is mandated by the Public Utility Commission of Texas, as well as a loss-of-load study for the North American Electric Reliability Corporation (NERC). In order to accurately model historical thermal unit availability for both studies, ERCOT is requesting that Resource Entities extract from the NERC Generating Availability Data System (GADS) certain unit-specific outage data for each of their thermal Generation Resources, and provide that data as instructed in the attached data submission form. ERCOT is requesting up to two Calendar Years (2018-2019) of GADS outage event and Equivalent Forced Outage Rate (EFOR) data for units that meet the following two criteria:

A. GADS data was submitted to NERC for Calendar Year 2018. (Wind unit outage data uploaded to the NERC GADS Wind system is not to be included in the submission.)

B. The thermal unit(s) are currently expected to be in operation, or could potentially be in operation, as of January 1, 2021.

The GADS data submissions are considered Protected Information under Nodal Protocols Section 1.3.1.1(q).

ACTION REQUIRED: Please return the attached data submission form and any accompanying data files, by April 1, 2020, via email to ClientServices@ercot.com.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

If you are receiving email from a public ERCOT distribution list that you no longer wish to receive, please follow this link in order to unsubscribe from this list: http://lists.ercot.com.

GADS Data Submission Form

REPORTING INSTRUCTIONS:

1. An example GADS Data submission form ERCOT is required for all units that meet reference. Please use this as an example when improving or building similar GADS data requests. An important piece of the following two criteria:
    a. GADS "Conventional" data was form is the capability to categorize the submitted for Calendar Year 2018; wind data to each utility, unit, and solar units reported do not need to be included event in your data submission.
    b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact order to feed the information for the preparer of into the data submission in case ERCOT staff has questions on the submitted GADS data probabilistic model.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link.
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

ercot

REPORTING INSTRUCTIONS:

1. Data submission is required for all units that meet the following two criteria:
   a. GADS "Conventional" data was submitted for Calendar Year 2018; wind and solar units reported do not need to be included in your data submission.
   b. The unit(s) are currently expected to be in operation as of January 1, 2021.
2. Data submittals are due no later than April 1, 2020.
3. In the shaded cells below, enter the contact information for the preparer of the data submission in case ERCOT staff has questions on the submitted GADS data.
4. The second and third tabs, named GADS_Unit Outage Details and GADS_EFOR, respectively, specify the GADS data elements to be reported for each thermal unit.
5. Provide the requested GADS data for Calendar Years 2018 and 2019, or for the subset of these years for which GADS data is available.
6. Resource Entities may submit the GADS data in separate files (one file for each tab) as long as the field names and ordering matches the two tabs. Although Excel files are preferred, text files (such as CSV) are acceptable.
7. This file, and any separate data files, should be sent in an email as attachments. The email address for the data submission is ClientServices@ercot.com.
8. This data submission is considered Protected Information under Nodal Protocols Section 1.3.1.1(q).**Respondent Contact Information:**
9. If the data file(s) is too large to be sent using email, a secure FTP file transfer will be arranged. Please send an email to ClientServices@ercot.com requesting a file transfer link. Contact Person:
10. Questions on the data form or submission process should be sent to ClientServices@ercot.com or your ERCOT Account Manager.

Title:
Telephone Number:
Resource Entity Name:
Email address:

Utility Code	Unit Code	Unit Name	Year	Event Type	Start of Event	End of Event	Net Available Capacity	Cause Code	Event Description

Utilit y Code	Unit Cod e	Unit Nam e	Yea r	Annua l-EFOR	EFOR -Jan	EFOR -Feb	EFOR -Mar	EFOR -Apr	EFOR -May	EFOR -Jun	EFOR -Jul	EFOR -Aug	EFOR -Sep	EFOR -Oct	EFOR -Nov	EFOR -Dec

System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Reliability Guideline: UFLS Studies

Action

Accept to post for a 45-day comment period.

Summary

The NERC SPIDERWG has developed a Reliability Guideline to provide guidance on impacts that higher penetration of DER may have on UFLS. The SPIDERWG requests authorization to post this Reliability Guideline for a 45-day industry comment period per the RSTC charter.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs

June 2021

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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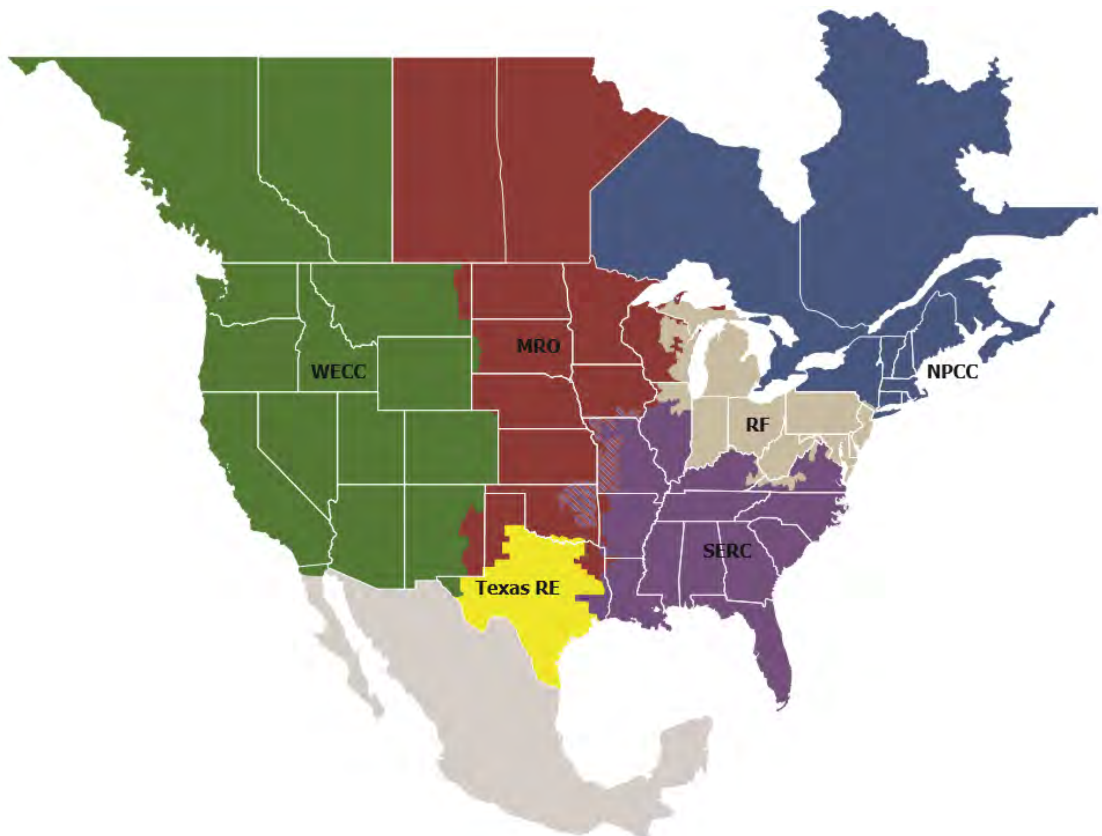
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

NERC's Planning Committee has requested the System Planning Impacts from Distributed Energy Resources (SPIDER) Working Group to "provide guidance on impacts that higher penetration of DER may have on system restoration, UVLS, and UFLS, and potential solutions or recommended practices to overcome any identified issues."[1] This document provides guidance on impacts that a higher penetration of DER may have on underfrequency load shedding (UFLS) programs, as well as recommended practices to overcome identified issues. The first section discusses the background and importance of UFLS to BPS reliability, as determined by FERC in Order No. 763.[2] The second section discusses impacts of DER to electrical island-level frequency, which UFLS programs are designed to support.[3] The third section discusses impacts of DER to UFLS program design. The fourth section concludes with recommendations.

In this document, a distributed energy resource (DER) is defined as "any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).[4] The fundamental premise of this document is as follows:

> *If a significant percentage of load is served by DER, electrical island-level frequency will be impacted. UFLS program design will follow from those impacts.*

From this premise, the importance of studying precisely how electrical island-level frequency will be impacted if a higher percentage of load is served by DER is thus clear. While NERC has called attention to the potential impact of DER to UFLS programs as early as 2011,[5] recent policy proposals and studies have emphasized the increased need for examinations into the impact of DER to UFLS programs developed by Planning Coordinators and implemented by UFLS entities, which may include Transmission Owners and Distribution Providers.[6] This document aims to provide industry notice of and guidance on the impacts of DER to UFLS programs.

In general, Planning Coordinators performing UFLS studies should:

- Include dynamic models of both U-DER and R-DER. At a minimum, U-DER voltage and frequency trip models should be included. Please note that R-DER, located on feeders, are usually on unity power factor without voltage control, and will trip at UFLS load shedding trip settings.
- Ensure accurate modeling of BPS-connected generators, including:
  - On-line operating reserves
  - Governor response
  - Voltage and frequency trip protection settings
  - Over excitation limitations and under excitation limitations, if present
  - Power system stabilizers, if present
- Ensure that additional cases reflecting other load conditions than Peak Load.

[1] System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Scope Document (December 2018). Available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG_Scope_Document_-_2018-12-12.pdf
[2] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).
[3] PRC-006-3: Automatic Underfrequency Load Shedding: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-006-3.pdf
[4] SPIDERWG Terms and Definitions Working Document – SPIDERWG Coordination Subgroup. Last Updated: April 9, 2019: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG_Terms_and_Definitions_Working_Document_-_2019-04-09.pdf
[5] Special Report: Potential Bulk System Reliability Impacts of Distributed Resources (August 2011): https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf
[6] IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018): http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PES_TR_7-18_0068

Introduction

Synchronous generators in North America operate around a nominal 60 Hz frequency, and frequency reflects the balance of generation and load. Situations where too much generation is produced cause frequency to increase and situations where insufficient generation is available cause frequency to decrease.[7] The change in frequency allows a continuous balance of generation and load at all times.

Under Frequency Load Shedding (UFLS) is a critical safety net designed to stabilize the balance between generation and load when a severe lack of generation is available to serve load causing frequency to fall rapidly (e.g., during an islanded operation). Automatic disconnection of end-use loads, typically through tripping of pre-designated distribution circuits or other pre-determined end-use customers, is intended to help recover frequency back to acceptable levels such that generation can rebalance and frequency can stabilize to within reasonable levels. UFLS operations serve to prevent large-scale outages from occurring; however, the BPS is planned, designed, and operated such that these types of safety nets only occur as a last resort for extreme or unexpected disturbances. The concept of UFLS and other safety nets is that controlled tripping of portions of the BPS, including end-use loads, may mitigate the potential for a larger and more widespread blackout.[8]

UFLS programs are designed to disconnect pre-determined end-use loads automatically if frequency falls below pre-specified thresholds. Some UFLS schemes include multiple levels of load disconnection to combat falling frequency to different depths. All UFLS frequency thresholds are set below the expected largest contingency event in each interconnection[9] to avoid spurious load disconnection, and are set above the highest expected set points for generator underfrequency protection (most notable 57.5 Hz) to avoid frequency damage.[10] Most commonly, the first stage of UFLS operation typically occurs around 59.5 Hz to 59.3 Hz; however, various regions of the BPS may have different thresholds for UFLS operation based on regional reliability needs.

A logic diagram that describes the high level procedures of a UFLS program is provided in **Figure I.1**. The actions the Planning Coordinators conduct are highlighted in blue and the UFLS Entity[11] actions are in grey. Where Planning Coordinators have overlapping areas, coordination among them and the respective UFLS Entities is required to ensure smooth operation of the designed scheme. As demonstrated in the diagram, there is a tight interchange of data between the Planning Coordinator (PC) and the UFLS Entities. Each PC is expected to provide high fidelity studies based on a strong knowledge of load and generation data, and the UFLS Entities are expected to be able to accurately and quickly provide a firm amount of load disconnection. These two main expectations can be tested with the increase of DER, especially those DERs that are unknown to the PC or UFLS Entities.

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[7] These increases and decreases cause electrical machines to speed up or slow down, respectively.

[8] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (2004) (Blackout Report).

[9] Refer to the latest version of NERC Reliability Standard BAL-003:
https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[10] Refer to the latest version of NERC Reliability Standard PRC-024:
https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[11] Per PRC-006, a UFLS entity can be a Transmission Owner (TO) or Distribution Provide (DP)

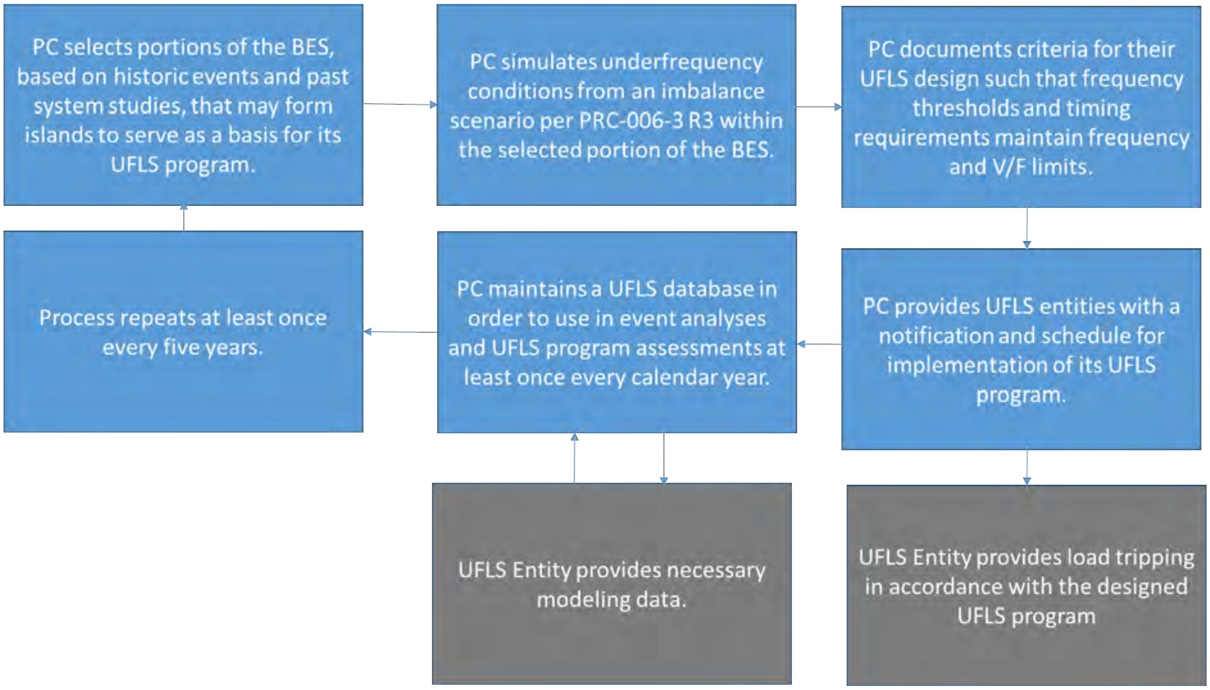

Figure I.1: Logic Diagram of Generic UFLS Schemes

UFLS Program Design and NERC Reliability Standard PRC-006

The Federal Energy Regulatory Commission (FERC) Order No. 763[12] adopted NERC Reliability Standard PRC-006-1 in May 2012, and subsequent non-substantive revisions[13] were made (up to the currently implemented PRC-006-5[14]). In the Order, FERC considered the impact of resources not connected to BES facilities on the development of UFLS programs. The primary focus was on ensuring an understanding and appropriate model to account for non-BES resources in UFLS design simulations. Specifically, in response to NERC's comments to the Notice of Proposed Rulemaking (NOPR), FERC was "persuaded…that Reliability Standard PRC-006-1 does not limit the resources that can be modeled in the UFLS assessments and that power system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system." Therefore, while PRC-006 does not require all generating resources to be explicitly modeled in studies for UFLS program design, it is well understood by industry that power flow and dynamic base cases typically represent the vast majority of BPS generating resources, as well as aggregate representation of end-use loads. In addition, more recently, aggregate representation of DERs have been modeled in certain regions. FERC also highlighted that accurately predicting system performance is critical for UFLS program design simulations, and that "inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system." As this guideline will describe, a reasonable representation of BPS generation, aggregate load, as well as aggregate DER is critical for appropriate determination of UFLS programs moving forward.

[12] https://www.ferc.gov/CalendarFiles/20120507124509-RM11-20-000a.pdf

[13] Please note that PRC-006-1, PRC-006-2, and PRC-006-3 (effective October 1, 2017) are substantively similar. As stated in FERC's Letter Order on the *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-006-2* (March 4, 2015), PRC-006-2 revised R9 and R10 (adding a language requiring the implementation of corrective action plans) and R15 (adding a requirement for Planning Coordinators to develop Corrective Action Plans). And as indicated in NERC's *Informational Filing regarding Reliability Standard PRC-006-3* (September 5, 2017), PRC-006-3 revised the regional Variance for the Québec Interconnection but made no other changes to PRC-006-2.
https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/PRC-006-2%20Letter%20Order.pdf
https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Ltr%20to%20Sec%20Bose%20re%20PRC-006-3.pdf

[14] Available here: https://www.nerc.com/pa/stand/reliability%20standards/prc-006-5.pdf

PRC-006-3 establishes design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events, and provide last resort system preservation measures. UFLS assessments include identification of expected island conditions for each PC area, and simulations of a frequency imbalance between generation and load of up to 25 percent that could occur from such island. The simulations should identify worst-case islanding conditions such that frequency thresholds of UFLS and the corresponding automatic load shedding will stabilize frequency acceptably.

NPCC, SERC, WECC, and the Québec Interconnection[15] have regional differences, particularly related to the UFLS program design considerations and the under- and overfrequency modeling curves. Refer to PRC-006 and the applicable Regional variances of the standard for more details. **Figure I.2** shows an illustration of the design performance and modeling curves for various Interconnections, and how UFLS frequency set points and generator underfrequency trip thresholds can differ across North America.

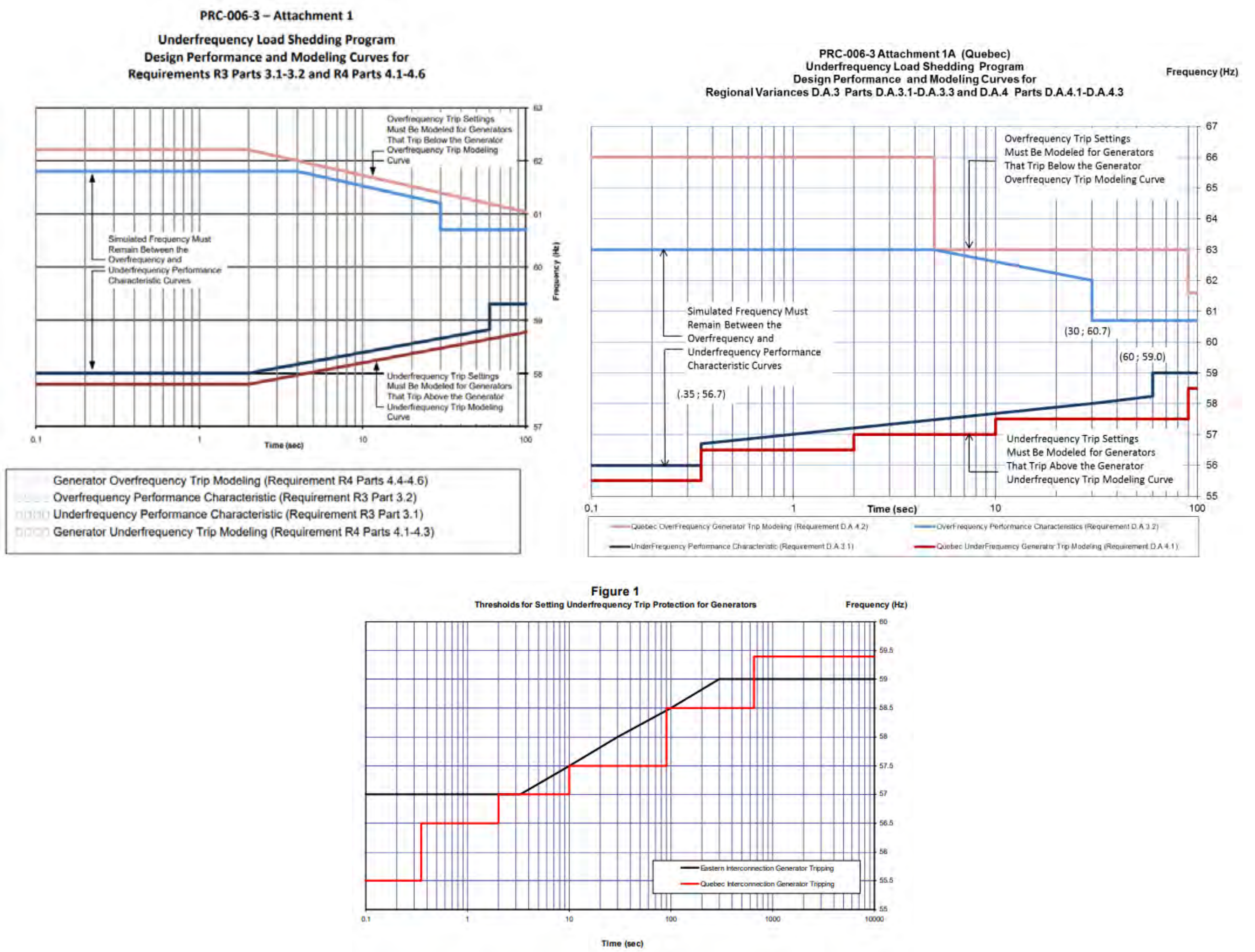

Figure I.2: UFLS Design and Modeling Curves for Different Interconnections

PRC-006 defines "UFLS entities" as those entities that are "responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program" established by the PC. UFLS entities may include Transmission Owners (TOs) or Distribution Providers (DPs). UFLS entities are responsible for implementing the UFLS programs

[15] The Quebec Interconnection is part of NPCC but has specific requirements associated with its UFLS program.

developed by the PCs, by determining the appropriate end-use loads or distribution circuits to use in the UFLS program and arming these feeders and circuits with UFLS relays. These activities are intended to meet the load shedding requirements developed by the PCs in order to stabilize any severe imbalance between generation and load after an electrical island has been formed.

To illustrate load shedding requirements in different PC areas, consider **Table I.1** showing the UFLS program frequency set points and amount of load shed at each UFLS stage for ERCOT, ISO New England, and PJM. In ERCOT, all distribution service providers (DSPs) are subject to the same load shed requirements. ISO-NE requires different stages of load shed depending on MW peak net demand. PJM, in contrast, requires different levels of shedding for its Mid-Atlantic Control Zone (MACZ), West Control Zone (WCZ), ComEd Control Zone (CECZ), and South Control Zone (SCZ). Appendix A provides a more comprehensive set of UFLS program settings across North America.

Table I.1: Load Shedding Requirements in ERCOT, ISO New England, and PJM

Frequency Set Point (Hz)	ERCOT[1]	ISO New England[2]			PJM[3]			
	All DSPs	Peak ≥ 100	50 ≤ Peak < 100	25 ≤ Peak < 50	MACZ	WCZ	CECZ	SCZ
59.5		6.5-7.5%	14-25%	28-50%		5%		
59.3	5%	6.5-7.5%			10%	5%	10%	10%
59.1		6.5-7.5%	14-25%			5%		
59.0							10%	10%
58.9	10%	6.5-7.5%			10%	5%		
58.7						5%	10%	
58.5	10%				10%			10%
59.5 (10s)		2-3%						
Total % Shed	**25%**	**29.5-31.5%**	**28-50%**	**28-50%**	**30%**	**25%**	**30%**	**30%**

1. See ERCOT Nodal Operating Guides Section 2.6.1(1) for further information.
2. See PRC-006-NPCC-1 for further information. Please note that Peak values are in MW.
3. See PJM Manual 36: System Restoration Section 2.3.2 further information.

Prior NERC Activities Related to Increasing DER and UFLS

NERC has been focusing on DER impacts to UFLS programs for the past decade. In 2011, the NERC Integration of Variable Generation Task Force (IVGTF) published a *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources*,[16] highlighted that at "high levels of DER, the effectiveness of existing underfrequency load shed schemes may need to be reviewed." The report described that "the profile of circuit loads can change and may no longer conform to the assumed circuit demand curve" with increasing penetrations of DERs, and used solar PV DERs as an example of offsetting gross demand during daytime periods. The example described that "if the circuits are part of an underfrequency load-shed scheme during periods of high DER production, the reduction in system demand may be less than assumed in the design of the scheme and will not result in the loss of load being proportional to the overall demand curve. If the quantity of DER is large enough to actually result in export to the bulk power system, isolation of the circuit as part of a load shed scheme could result in increasing, rather than reducing, system demand." Similarly, the NERC Distributed Energy Resource Task Force (DERTF) published a report in 2017, *Distributed Energy Resources Connection Modeling and Reliability Considerations*[17] highlighting that high levels of DER can have an impact on system protection (including safety nets) and will require closer coordination among DPs and transmission entities.

[16] https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf
[17] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

These prior activities serve as a foundation for further exploration into the impacts that DERs can have on UFLS program design, simulations to study UFLS settings, and appropriate operation of UFLS for large system imbalances in generation and load. Aligning with FERC Order No. 763, the planning assessments to develop a UFLS program rely on power system models that should suitably represent the expected system conditions facing the BPS in the future. This requires representing BPS-connected generating resources as well as end-use loads and DERs. Without appropriate accounting of the performance of these resources, PCs will be challenged in developing UFLS programs that are assured to operate appropriately for the expected frequency excursion event. The critical aspects of designing these UFLS programs pertaining to considering DERs in these studies is described in the following chapters.

Chapter 1: Impacts of DERs on Electrical Island Frequency

With the increasing penetration of DERs in North America, it is important to understand how DERs may impact or contribute to BPS frequency control and electrical island frequency response with respect to a large imbalance of generation and load. Understanding these impacts or contributions is paramount to developing effective UFLS programs in the face of higher penetrations of DERs in the future. At a high-level, increasing levels of DERs can impact BPS frequency response in at least the following ways:

- Lower system inertia and higher rate-of-change-of-frequency (ROCOF)[18]
- Higher percentage of generating resources unable to provide additional power injection during underfrequency conditions[19]
- Risk of DER tripping on off-nominal frequencies and high ROCOF prior to UFLS operation[20]
- Lack of visibility of DER output by BAs
- Variability and uncertainty in DER output

Consistent with FERC Order No. 763, each of these impacts further emphasizes the importance of modeling aggregate DERs in UFLS studies to ensure appropriate operation of UFLS actions, if needed. Even assuming that ROCOF is slow enough for UFLS to operate effectively and that sufficient frequency responsive resources are available to arrest frequency decline, PCs will need to ensure appropriate modeling of aggregate DER UFLS trip settings that could exacerbate any underfrequency condition. Further, the variability of aggregate DER output and its impact on variations in net load during different operating conditions poses challenges for PCs when performing UFLS studies and determining appropriate UFLS arming levels.

As the percentage of end-use load that is served by DERs increases, the performance characteristics of DERs will have an increasing impact on the imbalances between generation and load in an electrical island. Modeling aggregate amounts of DERs in BPS planning studies, particularly related to PC studies of UFLS program design per PRC-006-3, is of critical importance "accurately predict system performance."[21]

Impact of Modeled DER on UFLS Studies

While each of the identified major impacts of DER can be explored in further detail, a high-level overview of a recent study by ISO-NE effectively summarizes the impacts DER have on the study outcomes for UFLS. A more detailed report can be found in Appendix D. Of most important note is the difference between use of net load versus gross load in the simulation, and the impacts DER has on the simulation meeting regional criteria. The impacts for the ISO-NE are presented in **Figure 1.1.** In the figure, the orange line would not meet the criteria set for the ISO-NE operating as an electrical island as the deficiency caused by DER also tripping after UFLS action would not recover the frequency in time. So, ISO-NE tested a potential design change to their UFLS studies that compensated for the effect DER has on the island during these deficiencies, which resulted in the blue line that met the criteria. Again, more detail is found in Appendix D.

[18] This is of primary concern in areas with high Inverter-Based Resources (IBRs)
[19] Since, currently, the vast majority of DERs operate at maximum available power. This is particularly the case for renewable, inverter-based DERs (e.g., solar PV and small-scale wind DERs). Additionally, this can be due to DERs that do not have a governor to assist in frequency regulation.
[20] This is primarily of concern with regard to legacy DER. However, some distribution utilities are implementing their own DER interconnection protections, or are requiring DER to have trip settings that are not coordinated with UFLS.
[21] Order No. 763, 139 FERC ¶ 61,098 (2012) at Paragraph 29.

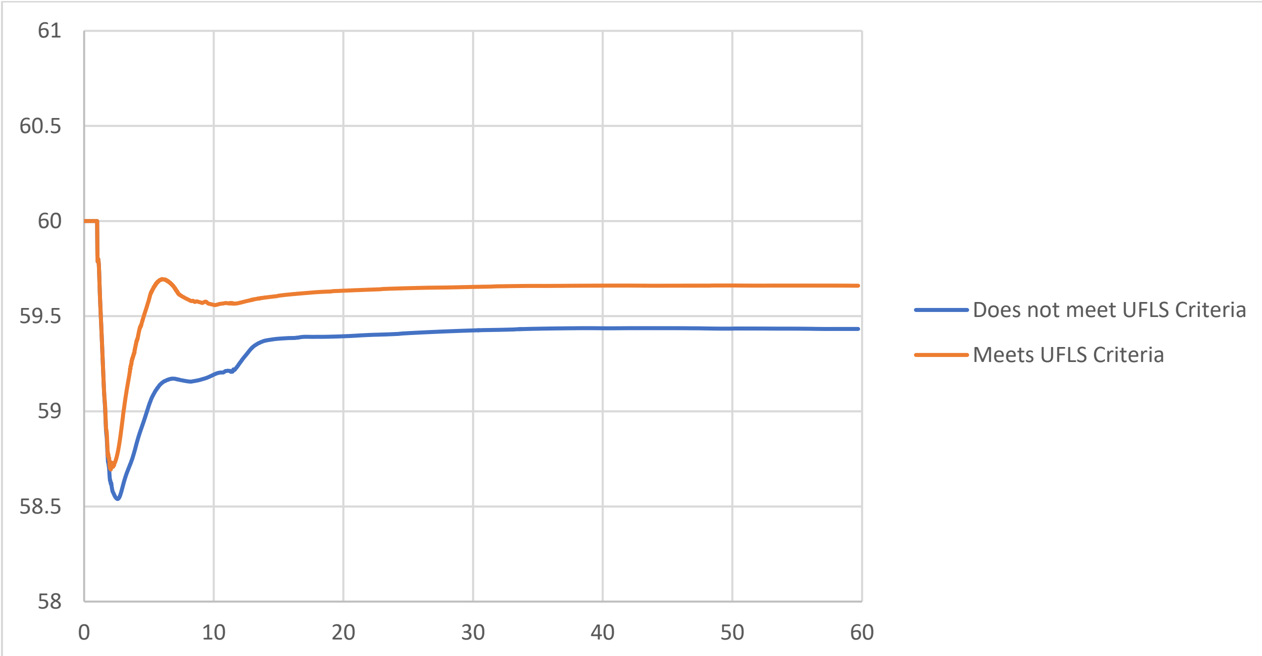

Figure 1.1: UFLS Program Design Changes Based on DER

Lower System Inertia, Higher ROCOF, and Displaced BPS Generation

Decreasing amounts of on-line synchronous inertia and the effect that can have on higher ROCOF have been observed in some Interconnections across North America and also internationally.[22] As the penetrations of both BPS-connected inverter-based resources and DERs (predominantly inverter-based) continue to increase, these resources may offset on-line synchronous generating resources that contribute to system inertia.[23] In response to a sudden loss of generation, kinetic energy is automatically extracted from the on-line synchronous machines, deterring the speed at which frequency will decline. Total system inertia depends on the number and size of on-line synchronous generators and motors. Greater system inertia reduces ROCOF following a disturbance, giving more time for primary frequency response to deploy and help arrest frequency decline prior to any UFLS operation. Therefore, smaller islanded systems (e.g., Texas Interconnection, Quebec Interconnection, Ireland, Hawai'i) are particularly prone to high ROCOF, low system inertia issues and will need to ensure appropriate mitigating steps to ensure reliable operation of the BPS.

Increasing penetrations of aggregate amounts of DERs across each Interconnection may displace BPS-connected generating resources. Further, BPS-connected inverter-based resources are already offsetting BPS synchronous generating resources. Therefore, it is expected that the displacement of synchronous inertia by both resources will cause system inertia to decline and ROCOF to increase. This becomes a problem only when ROCOF rises to a level that becomes unmanageable by the BA in terms of ensuring adequate primary and secondary frequency control.[24] High ROCOF in an electrical island may pose threats to UFLS programs since the available time to operate to adequately recover island frequency becomes shorter. Although UFLS programs could be redesigned to trip at lower frequencies to accommodate higher ROCOF or changing frequency dynamics, that option may only provide PCs with

[22] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," Atlanta, GA, March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[23] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[24] IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018): http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PES_TR_7-18_0068.

a temporary solution as system inertia continues to decrease[25]. Alternatively, more UFLS tripping is not an acceptable option from a reliability perspectives, as the system undergoes continual change in terms of its generation mix.

In the future, DERs may be able to provide fast frequency response (FFR) to support high ROCOF conditions during low synchronous inertia; however, at this time, this is not an expected operating mode for DERs based on current market rules and interconnection requirements. Very high penetrations of DERs and other inverter-based resources will require changes to these paradigms to ensure adequate frequency responsive reserves and performance of BPS frequency during normal and abnormal grid conditions such as large power imbalances.

Refer to Appendix B for a description of high ROCOF conditions analyzed by the Australian Energy Market Operator (AEMO) in the South Australia region of their system. Additionally, ISO-NE analyzed the same impact of reduction of inertia due to DER and found that as the DER offset the inertia providing resources in the simulation, not only did the ROCOF increase, but the settling frequencies also were altered. In **Figure 1.2**, the 60 second window of the simulation is shown, where the colors represent an amount of R-DER displacing BPS generation, tabulated in **Table 1.1**. The inertia was reduced in the simulation from the offset discussed above. Looking at the 5 second window of the same comparison in **Figure 1.3**, the recovery of the island frequency is also shown to be much slower with the increase of DER behind UFLS feeders. More details on this particular study can be found in Appendix D.

Key Takeaway

DER displaces BPS and BPS connected generation. This impacts the island level frequency by increasing the ROCOF and reduces the island's ability to recover from the imbalance scenario

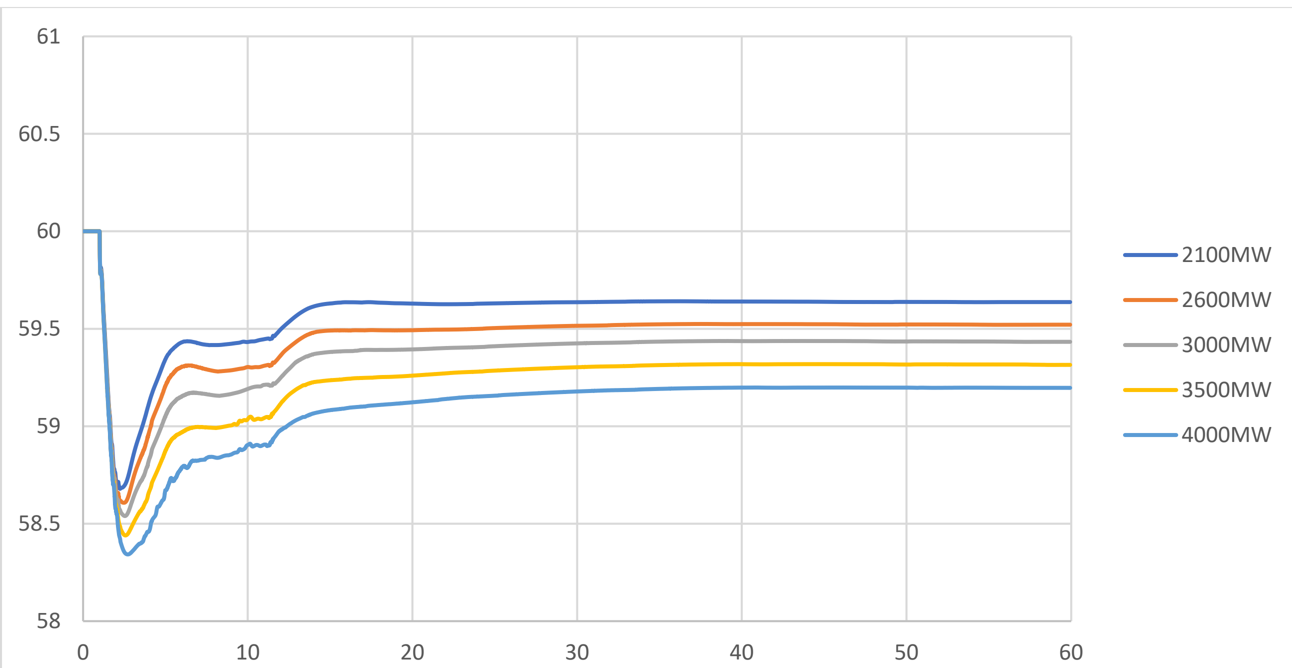

Figure 1.2: Impact of Increasing DER tripping from UFLS Action on Island Frequency Performance

[25] Furthermore, the underlying protection philosophy for UFLS should be reconsidered in high-IBR settings as the current UFLS program design protects against first swing stability of synchronous machines.

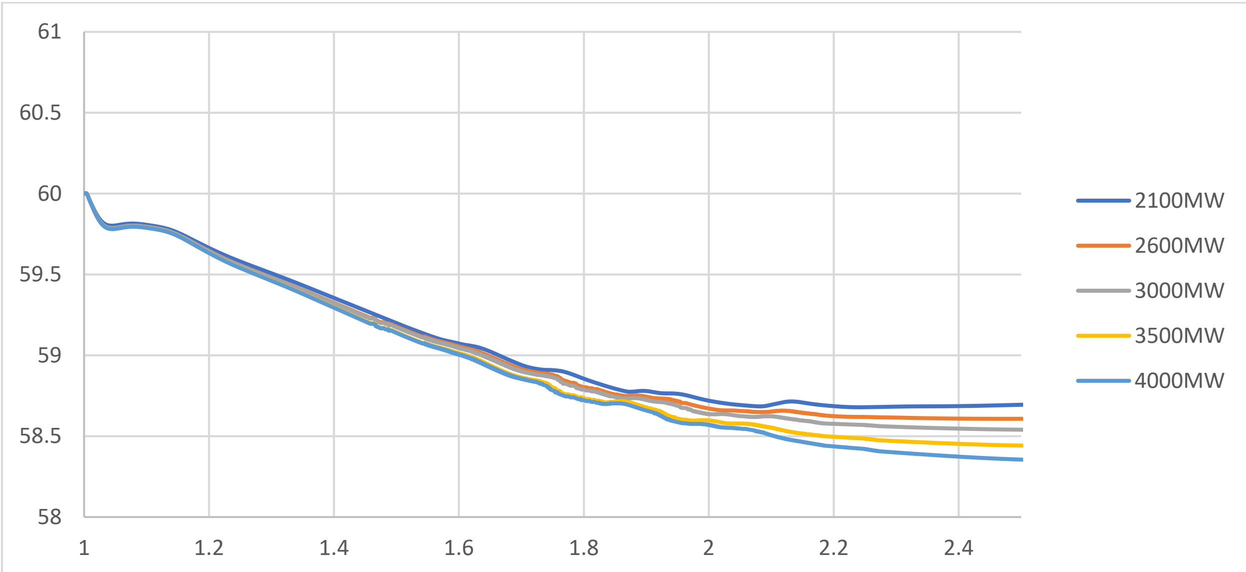

Figure 1.3: Zoomed in Comparison of Increasing DER tripping from UFLS Action on Island Frequency Performance[26]

Table 1.1: Scenario List of DER and UFLS Studies for Island Frequency Performance					
Scenario	**U-DER (MW)**	**R-DER (MW)**	**Total (MW)**	**U-DER Tripped (MW)**	**R-DER Tripped (MW)**
1	3,097	2,100	5,270	652	2,100
2	3,097	2,600	5,670	685	2,600
3	3,097	3,000	6,070	689	3,000
4	3,097	3,500	6,570	721	3,500
5	3,097	4,000	7,097	755	4,000

Higher Percentage of Generation Not Providing Frequency Response

Increasing penetration of DERs means that end-use load is increasingly served by DERs rather than BPS-connected generators. Many newly interconnecting resources, particularly renewable energy resources (i.e., inverter-based resources) with low energy costs are often run at maximum available power. Specifically, BPS-connected inverter-based resources are usually operated in this manner unless a curtailment signal[27] has been given by the Balancing Authority (BA) and inverter-based DERs are operated in a similar manner. DERs that are not under the control of the BA are not able to receive a curtailment signal and are programmed to provide maximum available power at all times. Therefore, the combination of BPS-connected inverter-based resources and inverter-based DERs operating at maximum available power and unresponsive to curtailment signals will continue to put pressure on the BAs to ensure that sufficient frequency-responsive reserves are available to arrest any large underfrequency events.[28] A lower number of units providing frequency response would result in a smaller subset of resources providing more incremental power to arrest frequency decline. This may put BAs in challenging situations unless long-term studies ensure that sufficient frequency responsive reserves are available.

[26] Note that the plot also demonstrates a change in ROCOF between the 2,100 MW modeled R-DER that trips on UFLS action scenario and the 4,000 MW scenario.

[27] Note that a curtailment signal issued by a BA or other grid operator may enable resources to have additional frequency responsive reserve to support BPS frequency; however, this should be coordinated by the BA and RC to ensure no other BPS performance metrics are adversely impacted.

[28] Synchronous DERs may or may not be frequency responsive; there are generally no requirements to provide that capability.

For UFLS studies, it is important for PCs to ensure their studies are representative of actual system conditions, particularly the dispatch of BPS-connected frequency-responsive resources, the coincident gross load, and gross load dynamics. As DERs continue to offset BPS generation, accurately representing generation dispatch will become more important.

Risk of Legacy DER Tripping

> **Key Takeaway**
> DER Tripping due to UFLS actions can pose a negative impact to the overall performance of the island in the UFLS Simulations

One key risk that DER, particularly legacy DER, may pose to BPS reliability during severe off-nominal frequency events is the potential for tripping off-line during the event. As a resource providing generation to the BPS, playing a balance role in the balance of generation and load, loss of generation will exacerbate an underfrequency event and cause frequency to fall further. With high or increasing penetrations of legacy inverters, this could pose a risk to BPS reliability either now or in the future. Further, understanding this risk is critical to designing UFLS programs and performing UFLS studies because these effects will need to be modeled appropriately with reasonable modeling assumptions built into the studies. An example of legacy DER tripping was explored by ISO-NE (See Appendix D for specific details) and demonstrates that the tripping of legacy DER can impact the performance of the feeder in the simulation greatly, as seen in **Figure 1.4**. The blue color is voltage at the U-DER bus, showing an extended overvoltage condition, and the orange line is the bus frequency. With the legacy DER tripping on overvoltage conditions after the UFLS action, a noticeable decline in frequency can occur.

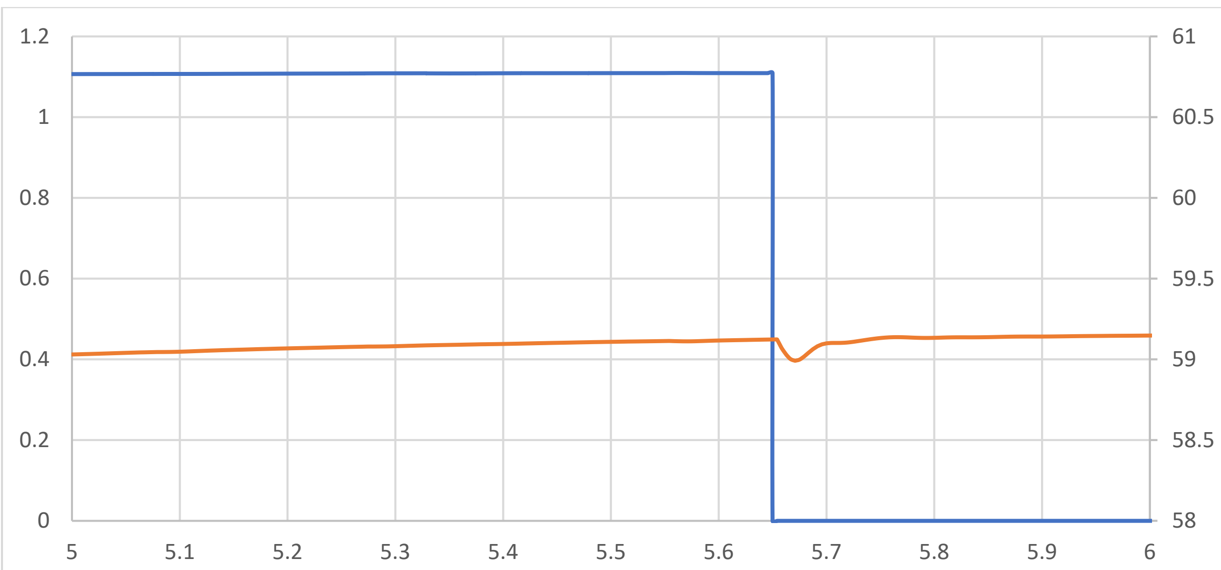

Figure 1.4: DER Tripping from Voltage Fluctuations after UFLS Actions.

The vintage of DER plays a key role in whether the resource is prone to tripping on underfrequency conditions. Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal while newer DERs compliant IEEE 1547-2018.[29] BPS-perspectives on the implementation and adoption of

[29] While the default frequency trip settings specified in IEEE 1547-2018 should ensure that DER remain connected during frequency events, some distribution utilities are requiring trip settings consistent with the previous IEEE 1547-2003 settings even on DER projects applying equipment certified to the new standard. Some distribution utilities are also applying their own protection equipment (e.g., reclosers) in series with DER interconnections set for very sensitive frequency tripping.

IEEE 1547-2018 are found in the *Reliability Guideline: BPS-Perspectives on IEEE 1548-2018*[30]. Consider the following recommendations when developing modeling assumptions for DERs:

- **Availability of DERs Compliant with IEEE 1547 Standard Versions:**[31] DERs installed across North America will have varying vintages based on the availability of DERs compliant with the various revisions of IEEE 1547. **Table 1.2** provides a rough estimate of the availability of compliant DERs, which can be used to determine the applicable propensity of DER to trip for underfrequency conditions associated with UFLS studies.

Table 1.2: DERs Compliant with IEEE 1547 Revisions [Source: EPRI]

Standard Revision	Test Procedures*	Availability of Compliant DERs†
IEEE 1547-2003	IEEE 1547.1-2005/UL 1741 "utility interactive"	After January 1, 2007
IEEE 1547a-2014	IEEE 1547.1/UL 1741 SA "grid support utility interactive"	After September 1, 2017
IEEE 1547-2018	IEEE 1547.1/UL 1741 SB "grid support utility interactive"	After January 1, 2022

* UL 1741 for inverters only[32]

† These are estimated dates only, using conservative assumptions and known implementation plans.

- **DERs Compliant with IEEE 1547-2003:** DERs compliant to IEEE 1547-2003 have the trip characteristics, per the standard, described in **Table 1.3**. During the period of development of IEEE 1547-2003, the general approach was for DERs to disconnect from the grid in the event of any major grid disturbance. This was the predominant mentality at the time since the focus was primarily distribution impacts (i.e., anti-islanding and coordination with reclosers) with minimal BPS considerations due to the low DER penetrations at the time. The general belief is that nearly all DER installations greater than 30 kW compliant with IEEE 1547-2003 used the most conservative trip settings of tripping when frequency falls below 59.8 Hz for more than 0.16 seconds. Therefore, applying this assumption in studies is also reasonable. However, this may require further investigation by the PC and DP and possible verification with frequency disturbance data that could inform modifications to aggregate DER models once more information is available.

Table 1.3: Underfrequency Trip Settings for IEEE 1547-2003 [Source: IEEE]

DER Size	Frequency Range	Clearing Time [s]†
≤ 30 kW	< 59.3	0.16
> 30 kW	< {59.8 – 57.0}*	0.16 – 300*

† For DER ≤ 30 kW, maximum clearing time; for DER > 30 kW, default clearing time.

* Adjustable values

- **DERs Compliant with IEEE 1547a-2014:** For the amendment to IEEE 1547-2003, frequency trip requirements moved to a set of default values with ranges of adjustability, as shown in **Table 1.4**. DERs compliant with IEEE 1547a-2014 are expected to trip, based on the UF2 default value, when frequency falls below 59.5 Hz for more than 2 seconds. While the range of adjustability for both UF1 and UF2 are wider, it is not expected that the default settings were widely changed at this time. Therefore, a reasonable can be to assume that DER will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds. Further investigation by the PC and DP may be needed.

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[30] Available here: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

[31] Inverter manufacturers stated that inverters were still shipped with IEEE 1547-2003 default settings even after UL 1741 SA inverters became available on the market since only a few entities required or desired longer trip times. PCs should assume worst-case trip settings unless authorities governing interconnection requirements (e.g., State regulators) have mandated specific ride-through capabilities and trip settings.

[32] https://standardscatalog.ul.com/standards/en/standard_1741_2

Table 1.4: Underfrequency Trip Settings for IEEE 1547a-2014 [Source: IEEE]				
	Default Settings		Ranges of Adjustability	
Function	Frequency [Hz]	Clearing Time [s]	Frequency [Hz]	Clearing Time [s]†
UF1	< 57.0	0.16	56–60	10
UF2	< 59.5	2.0	56–60	300

† Adjustable time, up to and including

- **DERs Compliant with IEEE 1547-2018:** The new IEEE 1547-2018 version of the standard sets much wider frequency trip settings that ensure DERs can ride through large frequency excursion events to support BPS operation during these abnormal conditions. **Table 1.5** shows the default settings and ranges of adjustability. Note that IEEE1547-2018 requires that the mandatory trip settings for abnormal frequency conditions be coordinated with the Area EPS operators as well as the RC. It also mentions that the settings should coordinate with regional UFLS program design, such that unexpected tripping of DERs compliant with IEEE 1547-2018 is unlikely for abnormal frequency conditions where UFLS operation would occur (i.e., DERs are able to ride through these events and continue providing power to the grid to support system frequency).

Table 1.5: Mandatory Underfrequency Trip Settings for IEEE 1547-2018 [Source: IEEE]				
	Default Settings*		Ranges of Adjustability	
Function	Frequency [Hz]	Clearing Time [s]	Frequency [Hz]	Clearing Time [s]
UF1	< 58.5	300	50–59	180–1,000
UF2	< 56.5	0.16	50–57	0.16–1,000

* Frequency and clearing time set points are field adjustable, and the actual applied trip settings must be specified by the Area EPS operator in coordination with the regional reliability coordinator (i.e., the RC) and typical regional UFLS programs. If the Area EPS operator does not specify any settings, the default settings shall be used.

Potential DER Tripping on High ROCOF

High ROCOF during islanded conditions may potentially cause legacy DERs to trip based on the settings programmed into the inverter. For example, during the large-scale disturbance in the United Kingdom on August 9, 2019 that resulted in UFLS operation, approximately 350 MW of DERs tripped on ROCOF protection.[33] The disturbance report stated that "some parts of the system may have experienced a [ROCOF] of 0.125 Hz/s."[34] The potential for DERs to trip on high ROCOF, particularly for legacy DERs, should be a consideration when designing UFLS programs.

In North America, there were no direct requirements for ROCOF tripping or ride-through in IEEE 1547-2003 or IEEE 1547a-2014. Clause 4.4 of IEEE 1547-2003 included a requirement that DERs "shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island," and included examples of ways to meet the requirement. Early methods employed by inverters may measure ROCOF to determine if an island exists, with relatively tight thresholds on this protection. Without any standardization, PCs will need to use engineering judgement to ensure that any potential DER tripping on high ROCOF does not pose an unnecessary risk to BPS reliability or UFLS operation.

IEEE 1547-2018, on the other hand, does address ROCOF ride-through, stating that DERs "shall ride through and shall not trip for frequency excursions" with magnitudes defined in the standard. **Table 1.6** shows the requirements for Category I, II, and III DERs related to ROCOF ride-through. Lastly, the standard states that ROCOF should be an average value over a measurement window of at least 0.1 seconds.

[33] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

[34] Many islanded networks are expected to have a ROCOF greater than this level, and some interconnections already have ROCOF conditions that exceed this level for generation loss contingencies. In the UK, a minimum ROCOF setting of .5 Hz/s is required.

Table 1.6: ROCOF Ride-Through for DER Compliant with IEEE 1547-2018 [Source: IEEE]		
Category I	**Category II**	**Category III**
0.5 Hz/s	2.0 Hz/s	3.0 Hz/s

Potential DER Tripping on High or Low Voltage

During severe contingency events on the BPS, system voltages may experience large variations or swings that could potentially trip DERs. This is more likely a concern or consideration for legacy DERs. Reliability studies should have reasonable assumptions for any potential aggregate DER tripping for abnormal voltage conditions. Refer to the appropriate vintage of IEEE 1547 to determine if voltage-related tripping should be modeled. The DER vintage alone may not fully indicate voltage-responsive protection settings of the inverters. DPs may or may not allow the utilization of DER voltage ride-through capability. Further, feeder-level over-voltage and under-voltage settings may not be coordinated with DER protection.

Lack of Visibility of DER Output by BAs

Many DERs, particularly behind-the-meter (BTM) DERs are not yet observable by, visible to, or controlled by the Balancing Authority in their efforts to control BPS frequency. While aggregate DERs have an impact on the generation-load balance since they provide power to the end-use loads like any other generating device, in many cases they are not under the control of the BA like BPS-connected or utility-scale DERs. For example, larger DERs may participate in ISO/RTO wholesale markets, and therefore may be observable and controllable by the BA; however, smaller BTM DERs likely are not participating in any markets (nor aggregation) at this time and therefore are not observable or controllable.

While this is more commonly associated with balancing and ramping concerns that the BA must manage (i.e., secondary frequency response), the lack of visibility and controllability poses challenges for establishing UFLS programs and overall frequency control. Without a complete understanding of how generation is serving load, TPs and PCs will have to use engineering judgment for long-term planning studies and BAs and RCs will also need to use engineering judgment for short-term reliability studies or real-time analyses.

Variability and Uncertainty in DER Output

Most newly interconnecting DERs are renewable energy resources whose output is dictated by atmospheric and meteorological conditions. The industry is becoming increasingly aware of the challenges of variability and the potential risks this poses to BPS reliability for BPS-connected resources such as wind and solar PV. However, adding this degree of variability and uncertainty to the distribution system will pose additional challenges in the future. This, coupled with the lack of visibility of DER output, may pose greater risks than those presented by BPS-connected variable energy resources.

Variability of DERs affects the amount of net load being served by the BPS at any given time. Increased variability of net load will affect the necessary level of load shedding needed to arrest and stabilize frequency in the event of a major imbalance between generation and load. Using offline studies performed in the long-term planning horizon, as required per PRC-006-3, will become increasingly obsolete as the system rapidly changes operating conditions and expected net loading conditions. Further, it becomes increasingly important for PCs to study a wider range of expected operating conditions, particularly with respect to DER output levels, to understand the worst case scenarios regarding UFLS operation. The likelihood and severity of potential under-arming or over-arming of end-use loads as part of the UFLS program design increases drastically when studies performed years prior become obsolete by rapidly changing system conditions presented by DER variability and uncertainty.

Illustration of DER Output Affecting UFLS Arming

To illustrate, consider a PC developing a UFLS program when faced with a reasonably high solar PV DER penetration in their footprint. The PC footprint is summer peaking, and therefore, winter conditions are not typically studied for UFLS operation. The scenarios considered by the PC include:

- **Summer Peak Load (Evening Hours):** During summer peak conditions around 6 PM on a hot summer day, gross load is around 5,000 MW and DER output is near zero. Gross load is therefore the same as net load, and the 25% deficiency studied in this case, as required by PRC-006-3 Requirement R3, is 1,250 MW. Since DER output is not variable at this time, there is no concern of over-tripping or under-tripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with High DER Output):** During spring light load conditions around 12 noon on a spring day, gross load is at 3000 MW and solar PV DER output is around 1500 MW. Therefore, the net load is 1500 MW and the 25% deficiency studied in this case is only 375 MW. Since DER output is assumed at its maximum, there is concern of over-tripping or under-tripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with No DER Output):** During spring light load conditions around 12 noon on a cloudy spring day, gross load is at 3000 MW but solar PV DER output is at 0 MW. Gross and net load are 3000 MW and the 25% deficiency studied in this case is 750 MW. If only the aforementioned spring light load case with DER output assumed was modeled, then the amount of net load tripping would be short by 375 MW (750 MW – 375 MW). This could pose a risk of the UFLS program failing to operate due to the DER variability.
- **Spring Light Load (Nighttime Hours):** During spring light load conditions late in the night on a mild spring day, gross and net load are again 3,000 MW since solar PV DER output is at 0 MW. This matches the case with no DER output during the daytime hours (assumption made here that day and nighttime light load are the same), and the previously studied case can suffice.

As mentioned, the introduction (and increasing penetration) of DERs presents a need for increased studies for UFLS program design due to the variability and uncertainty of DER output on any given day in the future. Even with accurate forecast values, the variability poses challenges for assuring that the UFLS scheme will operate as necessary for any imbalance presented. As shown above, if the assumption of DER on-line is made, there may be a risk of under-arming. Conversely, if the assumption of DER off-line is made, there may be a risk of over-arming during DER output conditions.

Some entities have moved to adaptive UFLS program designs in the face of high DER penetration conditions as the only viable solution to ensure correct operation of UFLS at any given time. For example Hawai'i Electric Light (HELCO) has implemented an adaptive UFLS program, which is described in more detail in Appendix C.

Chapter 2: Impact of DER on UFLS Program Design Studies

As described in Chapter 1, increasing penetration of DERs can have a significant impact on BPS frequency control and frequency response of the Interconnection. UFLS programs are built on long-term planning studies of expected future conditions, which often use interconnection-wide base cases as the starting point in which an islanded footprint for each PC is created. PCs will often adjust the dynamic models and operating conditions to represent conservative yet realistic assumptions of generation, load, transmission equipment, and DERs. Chapter 1 highlighted the effects that DER can have on BPS frequency response and UFLs; this chapter will focus on how those effects are represented in planning studies per PRC-006-3. Following FERC Order No. 763, PCs will need to model DERs within their respective studied island network to account for the performance and potential tripping of DERs. Specifically, PCs should consider the following impacts of DERs when performing UFLS studies:

- Modeling DERs in the steady-state and dynamic case used for the UFLS study
- Appropriately allocating any BTM DERs to aggregate load representations
- Representing any expected frequency- and voltage-related tripping from DERs
- Frequency set points
- Variability and uncertainty in DER output
  - DER output masking the total gross load
- Selection of distribution circuits or end-use loads

Recommended DER Modeling Framework

To account for the steady-state and dynamic effects that DERs can have on BPS performance during abnormal grid conditions, it is recommended that aggregate DERs be modeled in planning assessments using guidance proposed in previous NERC Reliability Guidelines (see **Figure 2.1**).[35] The DER modeling framework characterizes DERs as either utility-scale DER (U-DER) or retail-scale (R-DER). These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations, as needed. For reference, from the previous DER modeling recommendations, these definitions are provided here as a reference:

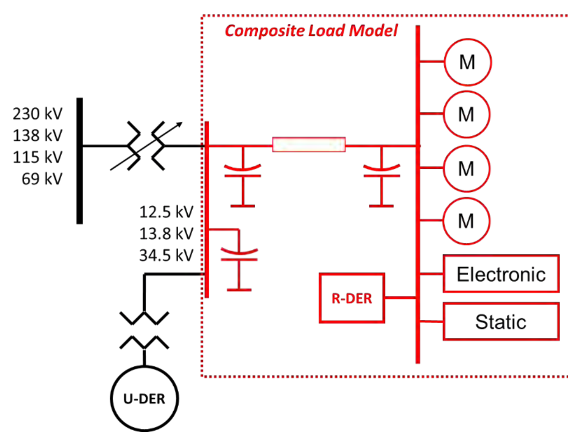

Figure 2.1: DER Modeling Framework

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder.[36] These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DER:** DERs that offset customer load, including residential,[37] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

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[35] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[36] Some entities have chosen to model large U-DER that are connected to load-serving feeders as U-DER explicitly in the base case as well. This has been demonstrated as an effective means of representing U-DER as well, and is a reasonable adaptation of the definition above.

[37] This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load serving feeder. Also, U-DER that is not connected close to the distribution bus or on dedicated feeders.

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system, and often refer to U-DER and R-DER for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling either individual large U-DER as well as aggregate amounts of the remaining DER as R-DER.

Studied Operating Conditions for UFLS Studies

Many of the fundamental concepts of UFLS program design do not change with the introduction of DERs in the islanded network. PCs still need to determine the operating conditions and dynamic response of interconnected resources (including generation and load-side resources) that cause the most severe frequency deviation for a defined percentage deficiency between generation and load in their islanded system. However, determining these conditions requires close consideration of aggregate levels of DER particularly as DER penetration levels increase.

Selecting Islanded Networks, Tripping Boundaries, and Study Techniques

Per Requirements R1 and R2 of PRC-006-3, each PC is required to “select portions of the BES (including portions of neighboring systems) that may form islands” and to “identify one or more islands to serve as a basis for designing its UFLS program”. In many parts of the North American BPS, UFLS programs are regional in nature. Choosing the PC area is the most logical and convenient island for study purposes for each PC. However, some areas may span multiple PC footprints (e.g., the northern part of the New England system with the New Brunswick system) and are therefore used in the same islanded system and coordinated among PCs.

The islanding boundary is critical to determine because it creates a complete island separated from the rest of the interconnected BPS for study purposes. Therefore, attention can be devoted to accurate modeling within the islanded network boundaries.

There are multiple ways to simulate the imbalance scenario, including but not limited to:

- **Reduced Power Flow Case Converting Tie Lines to Equivalent Loads:** A reduced power flow base case is created for each electrical island. All tie lines connecting the electrical island at the pre-defined island boundaries are replaced with equivalent loads or generators. In the dynamic simulation, those equivalent loads forming the electrical island and any additional BPS generation necessary to create the required load-generation imbalance are tripped simultaneously.
- **Islanding during Dynamic Simulation:** This approach uses the entire interconnection-wide or regional dynamic model rather than a reduced power flow model. The overall base case is configured with appropriate intertie flows into the PC area, and the electrical island is formed during the dynamic simulation by simultaneously tripping interties and any additional generation. Since this method uses the full interconnection-wide dynamic model with multiple islands formed, the simulations tend to run slow due to computation limitations in the commercial tools; therefore, this method may not be used by PCs for this reason.
- **Island in Power Flow Base Case:** In this case, the electrical island is the same as the PC area (i.e., islanded networks such as ERCOT) and this is reflected in the power flow base case. Therefore, the full amount of imbalance is created by tripping generating resources during the dynamic simulation.

Recommended Interpretation of Generation-Load Imbalance

Requirement R3 of PRC-006-3 states that each PC shall develop a UFLS program that meets a set of performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario[38] defined as:

$$imbalance = \frac{load - actual\ generation\ output}{load}$$

The term "load" is not capitalized[39] and therefore is subject to interpretation in PRC-006-3 regarding whether this term refers to gross load or net load in situations of DER penetration. A lowercase "load" term is only used in Requirement R3 of PRC-006-3 (although it shows up in other places in regional variances of the standard); however, how this term is used should be closely reviewed by PCs.

Consider how this equation is implemented in UFLS studies. The generation-load imbalance has historically been simulated by tripping boundary tie lines importing power to the island. Any additional power needed to make up the imbalance will come from BPS generators within the island being tripped off-line at the same time as the tie lines are tripped. Therefore, historically this equation actually should be:

$$imbalance = \frac{load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports))}{load}$$

Now consider the inclusion of DER into the scenario, which is differentiated from gross load. DER is inherently a generating resource that should be explicitly considered in the equation. This can be accounted for using the following equation:

$$imbalance = \frac{gross\ load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output)}{gross\ load}$$

With a fixed imbalance (i.e., 25%) set per the requirements of PRC-006-3, the equation can be rearranged to:

$$BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output = 75\% *\ gross\ load$$

The combination of BPS generation output, net tie line interchange (imports–exports), and DER output needs to be reduced to 75% of the gross load to meet the requirements of PRC-006-3. These reductions are typically prioritized using the following rules of thumb:

1. **Tie Line Imports and Exports:** The base case should be set up with reasonable expectations for imports and exports. Creating an artificial base case with heavy tie line imports that exceed any expected operating condition do not reflect a reasonable operating state and should not be used in simulation. However, the case can be set up to utilize the import capability to a reasonably justifiable level and exports can be minimized to the extent possible. Therefore, when the dynamic simulation trips the boundary lines of the islanded network, the reduction in tie line imports (less any exports) can be used to cover a portion of the deficiency.
2. **BPS Generation Tripping:** The next resource that should be tripped are BPS-connected generating resources, and should generally be resources that are able to provide frequency response since this creates a reasonable yet conservative assumption. If non-frequency responsive resources were tripped, this would lean towards an optimistic assumption with additional frequency responsive resources on-line than may occur in reality.

[38] Note that this imbalance is limited to 25% in PRC-006-3 and may have regional variances.

[39] As in, does not refer to a term used in the NERC Glossary of Terms: https://www.nerc.com/files/glossary_of_terms.pdf

Therefore, the remaining imbalance should consist of tripping frequency-responsive resources or a mix of responsive and non-responsive resources, using engineering judgment.

3. **DER Tripping:** DERs should not be tripped as part of the imbalance created to satisfy the requirements of the standard. As described in the preceding bullet, these resources are not typically frequency responsive and therefore tripping them to create the imbalance will be an optimistic assumption. Further, legacy DERs may have a risk of tripping on underfrequency conditions prior to reaching UFLS threshold, which will exacerbate the imbalance during the dynamic simulation. This needs to be analyzed by the PC as part of the dynamic simulation results separately from creating the imbalance. This is described in subsequent sub-sections of this chapter.

Consider an example system with the following assumed conditions for study:

- Condition: Spring Light Load
- Time of Day: 12 noon
- Gross Load: 2,000 MW
- DER Output: 500 MW
- Imports: 300 MW
- BPS Generation: 1,200 MW

The PC needs to determine an imbalance for this study case, which is based on 75% of the 2,000 MW gross load; meaning that BPS generation and net intertie flows collectively must be reduced to 1,500 MW (i.e., reduced by 500 MW). In this case, imports are at 300 MW and will be cut as part of the contingency definition. Therefore, an additional 200 MW of BPS-connected generation would be tripped at the same time as the severance from the rest of the system. Alternately, the imports may be modified to 0 MW and an electrical island formed prior to the dynamic simulation, where then 500 MW of BPS-connected generation would be tripped.

Key Takeaway

Assuming net load for calculating the deficiency to study the performance of an island per PRC-006-3 may not fully test the robustness of the UFLS program.

Assuming net load for calculating the generation-demand imbalance to study the performance of an electrical island per PRC-006-3 may not fully test the robustness of the UFLS program and could lead to under-tripping of sufficient DER to arrest severe frequency excursions.

Selecting Appropriate Study Cases

There are not specific requirements in the latest version of PRC-006 that require a specific operating condition to be studied (i.e., season, demand levels, BPS-connected inverter-based resource levels, or DER levels). Many entities may currently use summer peak conditions since these are traditionally the most stressed scenario in terms of a generation-load imbalance. However, electrical islands with high penetrations of inverter-based resources and DERs will likely change those most severe conditions. The risk of UFLS operation will likely increase during conditions of low gross load and high inverter-based resources (due to higher ROCOF, lower amount of on-line frequency responsive reserves, etc.). A one-size-fits-all approach likely will not work in the future, and PCs will need to evaluate which scenarios are most appropriate. Selecting an appropriate set of study cases is an important aspect performing UFLS studies and developing a robust UFLS program. Table 2.1 illustrates an example consideration of two distinct operating conditions.

Table 2.1: Comparison of Study Case Scenarios		
Characteristic	**Peak Summer Scenario***	**Light Spring Scenario†**
Demand	Maximum	Minimum
Synchronous Generation	Relatively higher dispatch, units on-line	Relatively lower dispatch, units off-line
Synchronous Inertia	Higher	Lower
BPS-Connected Inverter-Based Generation	Likely moderate solar PV and wind outputs, may be more conservative based on time of day and other assumptions	High solar PV and wind output, high renewables scenario
DER	Moderate to low DER (likely solar PV) output	High DER (likely solar PV) output
Imbalance	Highest level of imbalance due to gross load being at its maximum	Lowest level of imbalance due to gross load being at or near its minimum
ROCOF	Relatively lower ROCOF, less ROCOF concern	Relatively higher ROCOF, high ROCOF concern based on Interconnection
DER Tripping	Less DER output so less potential magnitude of DER tripping with UFLS operations; possible DER tripping on frequency and ROCOF conditions	Higher DER output so greater potential magnitude of DER tripping with UFLS operations; possible DER tripping on frequency and ROCOF conditions

* Peak Demand, Moderate Renewables Output, Moderate DER Output
† Light Demand, High Renewables Output, High DER Output

For each study case selected, an appropriate imbalance condition and setup of dynamic simulation will need to be conducted, and multiple study cases should be used to determine the worst-case frequency response performance for the electrical island. In most cases, at least a summer peak load and a spring light load operating condition are used to perform UFLS studies to ensure that the UFLS program is able to securely operate under these diverse sets of operating conditions. As the penetration of DERs continues to increase, additional cases should at least be considered by the PC and potentially studied based on identified risks. These cases include, but are not limited to, the following:

- **Summer Peak Demand (Evening Hours):** Summer peak conditions often occur during the early or later evening hours when DER output may be significantly reduced due to solar irradiance at that time. For systems that are summer-peaking, this condition will mathematically result in the largest imbalance necessary to meet the percentage defined in PRC-006-3. Therefore, this condition should be one of the cases studied during the UFLS design, if appropriate.
- **Winter Peak Demand (Nighttime Hours):** Systems with a winter peaking demand will need to consider these operating conditions as their highest peak gross demand conditions for the same reasons described in the summer peak demand case above.
- **Light Demand with High Renewables:** Light demand conditions typically occur during shoulder season, and most notably during the spring. Further, situations with high renewables output for BPS-connected inverter-based resources can drive low inertia operating conditions with the potential of high rate-of-change-of-

frequency (ROCOF).[40] This can pose a challenge for UFLS schemes to operate correctly, and should be studied where appropriate. Regarding DER, there are two considerations that should be made:

- **Light Demand with High DER Output:** Systems with a notable penetration of solar PV DERs should consider studying daytime light demand cases coupled with high output from BPS-connected inverter-based resources. Ensure that a reasonable amount of BPS frequency responsive and spinning reserves are carried in the simulation to reflect realistic operating conditions, and ensure that BPS generators are dispatched at reasonable output levels.
- **Light Demand with Low DER Output (Nighttime Hours):** Systems with or without a notable penetration of solar PV DERs should also consider studying nighttime light demand hours (where solar PV DERs are off-line, where applicable) as an alternative dispatch scenario. It is possible that these conditions are prone to higher wind power output. Other dispatch considerations may exist that warrant an additional data point to ensure UFLS operates as designed.

As mentioned, these are example considerations that should be made when selecting simulation cases for UFLS studies. Multiple cases should be studied to ensure reliable and secure operation of the UFLS under different operating conditions.

Example of Study Case Selection and Creation

Consider an example comparison between summer peak and light spring conditions, and how different system conditions affect case setup and generation dispatch assumptions. Table 2.2 shows the CAISO base case setup from the 2019 CAISO Transmission Plan. The starting case was modified to match imports to the 25% required generation-demand imbalance; therefore, interties can be tripped during the contingency to match the required imbalance. This resulted in only a 3,500 MW change in tie line flows in the summer peak case, but a 19,500 MW change in the light spring case. Lastly, the percentage of local demand served by DER and BPS-connected internal island generation were calculated. In the summer case, DERs in the local island are only serving 0.5% of demand and will likely have little to no impact on UFLS. However, in the light spring scenario, DERs make up over 48% of the local island generation mix for the hypothetical modified case. This illustrates how DERs can have a substantial impact to UFLS design, particularly during conditions when DER output is expected to be at or near its peak output conditions (which can often be coincident with low demand conditions, particularly for distributed solar PV).

Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data

Characteristic	Peak Summer Scenario	Light Spring Scenario
Time of Day	Hour Ending 19	Hour Ending 13
Gross Demand [MW]	57,510	31,050
DER Output [MW]	280	15,050
Pre-Contingency Case Imports [MW]	17,840	-11,860 (export)
BPS Generation On-line [MW]	41,160	29,060
25% Gross Demand Deficit	14,378	7,763
Modified Case Imports [MW]	14,378	7,763

[40] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," Atlanta, GA, 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data		
Characteristic	**Peak Summer Scenario**	**Light Spring Scenario**
Modified BPS Generation On-line [MW]	44,622	9,437
DER as % of Gross Demand	0.5%	48.4%
Local BPS Generation as % of Gross Demand	77.6%	30.4%

Modeling DER Tripping

Modeling any tripping of aggregate DERs is an important aspect of performing UFLS studies. As described in Chapter 1, DER can trip for different reasons and each of those reasons will be described here regarding how to account for or model these potential initiators of DER tripping. The aspects worth considering include, but are not limited to, the following:

- **DER Tripping on Underfrequency Conditions:** DERs across the electrical island may trip if their terminal measurement of frequency falls below pre-defined threshold values. Trip thresholds are likely based on existing regional or local interconnection requirements or may be default values specified in equipment standards such as IEEE 1547. These thresholds can be modeled in the DER dynamic models or with supplemental dynamic models.
- **DER Tripping on High ROCOF Conditions:** During the initial onset of the frequency imbalance, ROFOF within the electrical island may be high, and may lead to tripping. Considerations for potential tripping on high ROCOF should be made; however, existing dynamic models may be limited in capturing aggregate DER tripping on ROCOF.
- **DER Tripping as Part of UFLS Operation:** Modeling considerations will need to be made to accurately represent the potential of DER tripping as part of the UFLS operations. Modeling potential DER tripping from UFLS operations will determine the appropriate modeling practices for power flow and dynamic models.

Each of these modeling considerations is described below in more detail.

Dynamic Modeling of Aggregate DER Tripping on Underfrequency

As described above, the DER modeling framework recommends aggregate modeling of DERs in planning assessments, either as a U-DER or R-DER representation in the power flow base case and in dynamic simulations. U-DER are modeled with a generator record and can have an associated DER_A dynamic model applied; R-DER are accounted as part of the load record and can also have a DER_A dynamic model applied. The DER_A dynamic model includes frequency-related tripping, as described in NERC *Reliability Guideline: Parameterization of the DER_A Model*.[41] In the model, a filtered frequency signal is passed to frequency relay logic within the DER_A model. The frequency tripping logic is shown in **Figure 2.2**. If frequency tripping is enabled by the *ftripflag* parameter, voltage is above a defined threshold,[42] and frequency falls below the defined underfrequency trip setting, the full amount of DER modeled for that specific instance of the model will trip with a time delay set with the *tfl* and *tfh* parameters.

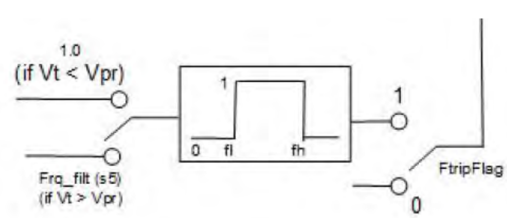

Figure 2.2: DER_A Frequency Tripping Logic [Source: PSS®E]

[41] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[42] Low voltage inhibit logic prevents frequency passing to the relay model if terminal voltage is less than or equal to the defined threshold.

As DER trip off-line due to underfrequency, frequency will continue to decline. Therefore, reasonable modeling of potential DER tripping is important since it may exacerbate the generation-load imbalance. Sensitivity studies should consider any conservative assumptions on potential DER tripping to determine if this has any adverse impacts to the UFLS program.

Modeling Potential DER Tripping on High ROCOF

As mentioned in Chapter 1, high ROCOF during electrical island conditions could cause legacy DERs to trip[43]. Since there are no requirements or standards to develop ROCOF protection models, PCs should use engineering judgement to determine any potential risks that additional DER tripping on high ROCOF could pose to electrical island frequency control. There are currently no known dynamic models in commercially available software tools that can be applied to both U-DER (generator records) and R-DER (either as part of the load record or as a component in a modular dynamic load model) for ROCOF protection.[44]

Therefore, the best approach is for PCs to perform dynamic simulations and to identify the highest ROCOF observed during the simulation. If ROCOF exceeds a pre-determined threshold where DER may be prone to trip (based on engineering judgment), then the PC should determine an appropriate amount of DER to trip at that point in the simulation and re-run the simulation to see how this sensitivity affects frequency response of the electrical island. Sensitivity studies are recommended to ensure that any excess DER tripping does not affect performance of the UFLS program.

Modeling DER Tripping as Part of UFLS Operation

Modeling considerations should capture potential tripping of aggregate DER as part of UFLS operations once frequency has fallen below UFLS thresholds. There are many different ways to model and represent this tripping in the dynamic simulations, and requires coordination between power flow and dynamics modeling practices. UFLS programs often have multiple load shed set points that trigger local load shedding relays based on pre-defined frequency trip settings. As described, this includes specific distribution feeders or individual large end-use customers based on the UFLS program design. In the power flow and dynamic models, the individual feeders or groups of loads are often lumped together as an aggregate load and may need to be separated or partially tripped in the studies based on utility practices.

Consider **Figure 2.3** to illustrate this concept. Assume that this system has U-DER modeled as individual generator records and R-DER included as part of the load record and composite load model (in dynamics). Assume that if U-DERs mainly are fed from the distribution substation and therefore are generally not tripped as part of the UFLS program. Therefore, there is no issue with modeling the consequential tripping of these resources as part of the UFLS operation. However, this is a concern for the R-DERs since some amount of R-DERs may be tripped when distribution circuits are tripped during UFLS operations. In this case, different amounts of DERs will be tripped at different UFLS operations based on the percentage of load tripped (assuming an equal distribution of R-DER across the various feeders). Now assume that the load and R-DERs will be tripped at three stages (e.g., at 59.5, 59.1, and 58.7 Hz).

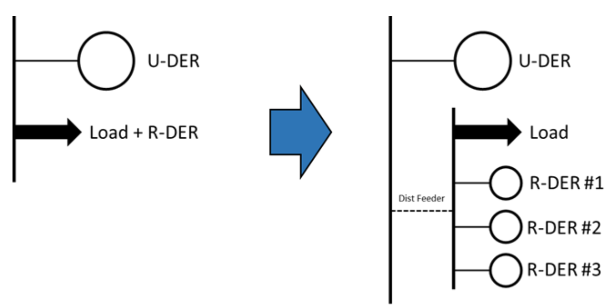

Figure 2.3: Example Modeling of Aggregate DERs Tripping with UFLS

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[43] Additional ROCOF protections implemented by, or required by, the DP may also result in DER tripping.

[44] Some load shedding relay models such as *lsdt7* or *lsdt8* are able to model ROCOF-based tripping; however, these models are applied to load records and therefore will trip the load component in addition to any DERs. Therefore, these models are generally not well suited for capturing DER tripping for R-DER modeled as part of the composite load model.

The issue arises in the dynamics modeling of the R-DERs included as part of the load record and composite load model. The DER_A dynamic model trips the full amount of DER once the frequency trip threshold is crossed, and does not include staged trip settings in the dynamic model. Therefore, the R-DERs will need to be separated out into individual models that can be separately tripped. In the dynamic model, the frequency trip settings can be configured for each R-DER to trip once the pre-established thresholds are crossed. For example, R-DER #1 may trip at 59.5 Hz, R-DER #2 may trip at 59.1 Hz, and R-DER #3 may trip at 58.7 Hz.

Regarding the stand-alone load record (since the DER elements have been separated), load shedding relay models such as *lsdt7* or *lsdt8* can be used to trigger various levels of load tripping all combined into one dynamic load model record.

As mentioned, there are multiple ways this can be set up in the power flow and dynamics models; however, this modeling practice is described here as a reference for consideration.

Performing Dynamic Simulations for UFLS Studies

As UFLS program design requires a Planning Coordinator level study to initiate the design of the UFLS program, the PC will need to make sure a few key parts in the dynamic simulation are maintained in order to effectively capture the impacts DER has to the design of the UFLS program. These considerations will provide a heightened confidence that the UFLS program captures the impact of DER.

Key considerations for Planning Coordinators performing UFLS studies with aggregate DER represented include the following:

- Planning Coordinators should include dynamic models of both U-DER and R-DER. At a minimum, U-DER voltage and frequency trip models should be included. Please note that R-DER, located on feeders, are usually on unity power factor without voltage control, and will trip at UFLS load shedding trip settings.
- Planning Coordinators should ensure accurate modeling of BPS-connected generators, including:
    - On-line operating reserves
    - Governor response
    - Voltage and frequency trip protection settings
    - Over excitation limitations and under excitation limitations, if present
    - Power system stabilizers, if present
- Planning Coordinators should ensure that additional cases are tested that reflect load conditions other than Peak Load.

Chapter 3: Coordinating with UFLS Entities

PRC-006-3 includes the term "UFLS entity", referring to "all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the [PCs]." These entities may include TOs, DPs, or both. Requirement R3 describes that the PC, upon developing its UFLS program, will notify UFLS entities within its area of the program and a schedule for implementation by UFLS entities. Requirement R9 states that each UFLS entity shall "provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation…" for any PC areas in which it owns assets. UFLS entities are provided discretion regarding how specific levels of load are armed and automatically tripped to meet the requirements outlined by the PCs as part of the UFLS program. This leaves flexibility for UFLS entities to determine which distribution circuits, feeders, or specific loads will be selected. With the growing penetrations of DERs, it is important for UFLS entities and PCs to closely communicate how specific loads or feeders are selected and to what degree DERs could impact effective UFLS operation. Figure 3.1 shows the continuous feedback loop needed as DERs penetrations continue to increase.

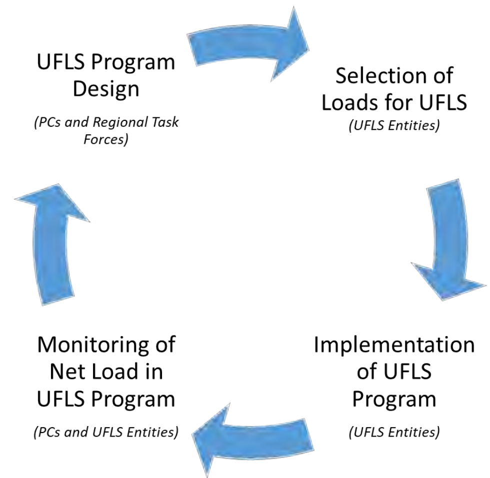

Figure 3.1: Continuous Feedback Loop of UFLS Program Design

There are key factors that should be considered by UFLS entities in coordination with their respective PCs when developing and implementing effective UFLS programs in the face of increasing DER penetrations. These include, but are not limited to, the following:

- Selection of loads participating in the UFLS program
- Impacts of DER aggregators or other DER management systems
- Coordination of any advanced DER controls (i.e., frequency response capability) with regional UFLS settings and BPS frequency control needs
- Coordination of UFLS with distribution-level hosting capacity analysis

These are described in more detail in the following subsections.

Selection of Loads Participating in the UFLS Program

The primary focus or concern regarding the coordination between UFLS Program design and implementation is the selection of feeders or end-use load customers participating in the UFLS Program. UFLS studies are only required to be performed on a periodic basis; however, DER penetrations are rapidly growing in many areas of North America and can potentially impact the effectiveness of UFLS operations. An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS.

> **Key Takeaway:**
> An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS.

For example, assume a UFLS entity has been assigned 50 MW of net demand that should be armed and automatically shed as part of UFLS operations. The UFLS studies performed by the PC did not account for DERs in this area since penetrations were not significant. However, in the last few years, the DP has observed fairly significant DER growth on many of its feeders. The PC had previously only used peak summer conditions for UFLS studies, which assume peak demand around 6 PM. Therefore, during peak demand conditions, the UFLS would likely still operate as expected since DER output may be low at this time. However, during low demand, high solar DER output, low system inertia conditions, the DERs may reduce the net demand on those feeders. Assume now that instead of having 50 MW armed, the UFLS entity inadvertently is only arming 30 MW. The deficit of 20 MW of net demand armed will cause insufficient amounts of load shedding to ensure the UFLS operates as expected. Further, if this is observed across multiple DPs (i.e., UFLS entities), the issues may be further exacerbated across a wider PC footprint.

During the selection of loads participating in the UFLS program, DPs should consider the following:

- PRC-006-3 does not specify which specific end-use loads, distribution circuits, or feeders should be chosen by DPs for inclusion in the UFLS program and automatic tripping if BPS frequency reaches these levels. That discretion is left to the DP based on their specific system needs and characteristics.
- Most commonly, the PC is specifying a net load quantity in terms of demand (MW) needed to be armed at the T-D interface. DPs should confirm with their PCs that the amount of arming is representative of a net demand quantity.
- Distribution circuits or feeders that have DERs intermixed along the circuit, resulting in variable net loading at the monitoring point (i.e., head of the feeder) inherently create more variability in the amount of net load that may be armed at any given point. Therefore, it is common practice for DPs to attempt to select circuits, loads, or feeders where DERs are not prevalent.
- As the penetration of DERs increases in any given area, the likelihood of identifying feeders with minimal DER impacts may be significantly reduced. Therefore, feeders with DERs may need to be used as part of UFLS programs. In these cases, close coordination between the DP and PC is needed. DPs and PCs should coordinate on at least the following:
    - DPs should confirm that the simulations performed by the PC include installed and forecasted DER penetrations appropriately. DP selection of UFLS-armed feeders or loads to meet the UFLS program objective at all times will increasingly become a challenge. Tripping feeders with high DER output will cause less net load to be tripped; tripping feeders with low DER output will cause more net load to be tripped. This needs to be accounted for in studies and in actual implementation.
    - DPs should confirm that the simulations performed by the PC model aggregate DER with appropriate voltage and frequency trip settings. DERs that are expected to trip during voltage or frequency excursion events further complicate selection of UFLS-armed circuits, and may lead to unexpected generation loss during the contingency that could further exacerbate the underfrequency conditions.
    - DPs should clearly articulate which feeders are selected for UFLS arming and automatic tripping, and identify any cases where DER variability could affect the net demand armed.
        - Variations of time of day, season, etc., should be considered by the DP when informing the PC of any variability in DER output affecting net loading of UFLS-armed circuits.
- Targeting specific loads, circuits, or customers for inclusion in the UFLS program may require greater granularity in the future compared to past experience, particularly as the penetration of DERs for any given UFLS entity continues to increase.
    - Conventional UFLS relaying (i.e., on a circuit-level basis) may become obsolete or may require additional solutions when faced with increasing DER penetrations. For example, battery energy storage systems (BESSs) may be able to provide fast-responding net load reduction by providing fast discharging capability when UFLS levels are reached. This may offset the need for tripping of end-use load customers in the future, and may help compensate for a depleting number of eligible UFLS feeders.

The considerations listed above are important for the DP to consider when selecting feeders or end-use loads for participating in the UFLS program; however, they are also relevant for PCs to consider as they design their overall UFLS program with increasing DERs across their PC footprint. PCs may consider working with their DPs to develop ranking criteria on feeder selection for UFLS programs, consider possible modifications to UFLS thresholds or trip levels, and establish regular communications with UFLS entities to ensure DERs are being sufficiently accounted for during UFLS program design. Appendix C describes a situation where the UFLS program in the HELCO footprint required an adaptive setting due to high DER penetration levels. This requires close coordination across the PC and DPs to implement these advanced types of tools.

Impacts of DER Aggregators or Other DER Management Systems

DER management systems (DERMS) or DER aggregators are new functions that are surfacing across the industry in the face high penetrations of DERs. DERMS or other DER aggregators do not modify the electrical connection of DERs or other load modifiers (e.g., demand response); however, DERMS may modify the behavior of these resources to provide a specified or contracted response to support the grid. For example, DERMS may be used to provide frequency responsive reserves or contingency reserves or could be used for ramping or balancing, depending on the contracts or markets put in place that could enable this technology. While this is an evolving area, it will have an effect on UFLS operations and UFLS program design. Some questions that PCs and UFLS entities should consider include:

- How are the implementation and operation of DERMS or DER aggregators tracked and accounted for in UFLS studies?
- Which entity is sending any control signals to the DERMS in response to BPS disturbances?
- Is the DERMS configured or contracted to provide grid-supportive functions such as frequency response to underfrequency events?
- How will the response of a DERMS affect overall UFLS program design, and how is this modeled appropriately?

These questions all highlight the complexity of introducing DERMS or other aggregation components to the overall grid. Reliable operation of a UFLS program to avoid widespread outage conditions is a critical function of BPS safety nets and a critical element in reliable operation of the BPS.

Coordination of UFLS Program with Possible DER Frequency Response

The inclusion or exclusion of feeders or circuits from participating in UFLS programs and potential automatic tripping during UFLS operations should not be confused with any preclusion or prohibiting of DERs from providing grid-supportive functionality or other essential reliability services. For example, if circuits are not chosen for UFLS operation due to increasing DERs, this should not affect the development of any interconnection requirements regarding those resources having frequency response capability and being able to provide that service to the BPS either now or in the future.

UFLS is a safety net function for severe contingency events when an imbalance of generation and load requires a fast-responding and automatic disconnection of select end-use loads from the system to rebalance system frequency. Prior to reaching those UFLS frequency thresholds, all generating resources (including DERs, if able to respond) and end-use loads[45] can help arrest frequency declines. DERs and BPS-connected generation can increase active power output, if configured in a manner to do so, to support overall BPS frequency response. As mentioned above, DERMS or other aggregators may control many individual DERs in the future to provide this service to the BPS. Further,

[45] Either through inherent frequency sensitivity of direct-connected motor loads or through dedicated end-use loads providing frequency responsive services.

existing DERs participating in wholesale electricity markets may also be capable of providing these services to support BPS operations. These functions support overall frequency control and in some ways help mitigate the potential operation of UFLS in the first place.

PCs and UFLS entities should ensure that any existing requirements or future requirements not preclude DERs from being able to support BPS frequency and provide essential reliability services.

Coordinating UFLS Programs with Distribution-Level Hosting Capacity

Key Takeaway:
State-level regulatory authorities should align hosting capacity analysis with UFLS program design to ensure that sufficient load, or load resources, are enabled to trip to arrest declining BPS frequency.

Some state-level regulatory authorities require DPs and TOs (UFLS Entities) to facilitate interconnection of DERs in areas of the distribution system with ample "hosting capacity," defined by the Electric Power Research Institute (EPRI) as "the amount of DER[s] that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades."[46] According to EPRI, hosting capacity is a function of location, DER type, and circuit configurations (see Figure 3.2). Distribution circuits or feeders that already have DERs intermixed along the circuit have less available hosting capacity; distribution circuits or feeders that do not have DERs have more available hosting capacity.

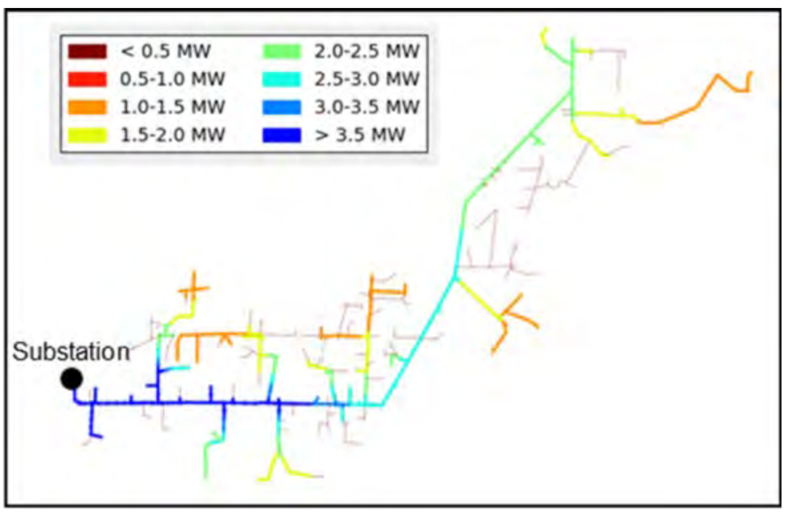

Figure 3.2: Example Hosting Capacity Heat Map [Source: EPRI]

Thus, state-level requirements facilitating the interconnection of DERs on feeders with hosting capacity (i.e., more load, less DER) will likely result in DER development on the same feeders that are designated for UFLS (again, more load, less DER). Greater levels of load enabled to trip on UFLS will in turn be required. PCs, UFLS entities, and state-level regulatory authorities should coordinate hosting capacity analyses with UFLS program design to ensure that interconnection of DERs does not inadvertently result in the degradation of UFLS required to support reliable operation of the BPS.

[46] https://www.esig.energy/blog-methods-applications-hosting-capacity/

Appendix A: UFLS Programs across North America

This Appendix compiles some of the presently effective UFLS program settings across North America, simply as a useful industry reference. Table A.1 to Table A.3 show the frequency set points and amount of net demand tripped when frequency reaches each set point for the Eastern, Western, and Texas Interconnections, respectively. Note that cells that are greyed out are simply not in effect for that specific entity.

Table A.1: Various Eastern Interconnection UFLS Program Settings

Frequency Set Point (Hz)	NPCC*			PJM				MRO/MISO			SERC
	Peak ≥ 100	50 ≤ Peak < 100	25 ≤ Peak < 50	MACZ	WCZ	CECZ	SCZ	3-Step (15 UFLS Entities)	5-Step (5 UFLS Entities)	1-Step (9 UFLS Entities)	Target Load Shed
59.6											7.4%
59.5	6.5-7.5%	14-25%	28-50%		5%						
59.4											5.2%
59.3	6.5-7.5%			10%	5%	10%	10%	8.3-15.3%	5.1-12.6%	32.1-100%	
59.2											5.2%
59.1	6.5-7.5%	14-25%			5%						
59.0						10%	10%	7.2-16.4%	5.9-12.6%	100%	5.2%
58.9	6.5-7.5%			10%	5%						
58.7					5%	10%		6.3-13.1%	4.7-10.7%	100%	6.3%
58.5				10%			10%	8.3-12.3%	0.6-6.5%	100%	
58.4											4.3%
58.3								8.7-12.7%	0.2-6.8%	32.1-63.8%	
58.2											2.2%
59.6 (15 +/-.5s)											2%
59.6 (22 +/-.5s)											3%
59.5 (10s)	2-3%										
Total % Shed	**29.5-31.5%**	**28-50%**	**28-50%**	**30%**	**25%**	**30%**	**30%**	**28-43%**	**29-43%**	**32.1-100%**	**40-44%**

*Please note that the Québec Interconnection has five threshold stages and four rate-of-change (slope) stages of load shedding.

Table A.2: Western Interconnection[47] UFLS Program Settings			
Frequency Set Point (Hz)	Coordinated Plan	NWPP Sub-Area	Southern Island Sub-Area
59.6			.07%
59.5			4.0%
59.3		5.6%	
59.2		5.6%	
59.1	5.3%		2.8%
59.0		5.6%	
58.9	5.9%		6.5%
58.8		5.6%	
58.7	6.5%		7.4%
58.6		5.6%	
58.5	6.7%		7.4%
58.3	6.7%		7.3%
Total % Shed	**31.1%**	**28%**	**35.4%**
59.3 (stalling)	2.3% (15 sec)	2.3% (15 sec)	2.9%
59.5 (stalling)	1.7% (30 sec)	1.7% (30 sec)	2.1%
59.5 (stalling)	2.0% (1 min)	2.0% (1 min)	2.3%

Table A.3: Texas Interconnection UFLS Program Settings	
Frequency Set Point (Hz)	ERCOT
	All DSPs
59.5	
59.3	5%
59.1	
59.0	
58.9	10%
58.7	
58.5	10%
59.5 (10s)	
Total % Shed	**25%**

[47] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Off-Nominal%20Frequency%20Load%20Shedding%20Plan.pdf&action=default&DefaultItemOpen=1

Appendix B: AEMO Analysis of High ROCOF Conditions

System inertia has declined in South Australia since 2012 due to retirement of synchronous generation, as shown in **Figure B.1**. In August 2016, AEMO issued a report, *Future Power System Security Program Progress Report*, highlighting concerns over historical frequency response trends and system inertia. Specifically, the report described the possibility that the decline in system inertia, causing a rapid increase in ROCOF following large disturbances, may cause frequency to decline too rapidly in South Australia for "UFLS to produce a well-coordinated and well-graded disconnection of load to arrest the frequency" during historical "non-credible" separation events.[48,49,50] Under Australia's National Electricity Rules, 60 percent of expected demand must be available to shed "in manageable blocks spread over a number of steps within under-frequency bands from 49.0 Hz down to 47.0 Hz as nominated by AEMO."[51]

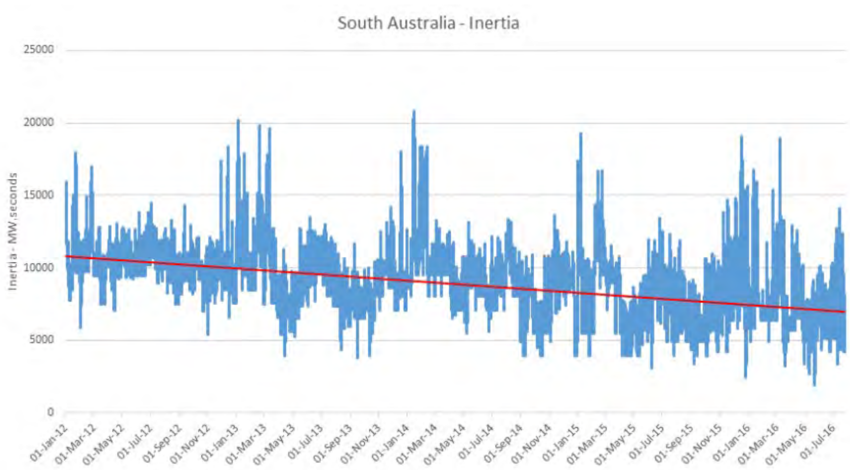

Figure B.1: System Inertia in South Australia [Source: AEMO]

A month later, on September 28, 2016 at 4:16 PM local time, South Australia's 1,826 MW of demand was supplied by 48% wind generation, 18% gas generation, and 34% electricity imports (limited at 650 MW).[52] **Figure B.2** shows the resource mix at the time prior to the disturbance. According to AEMO, tornados tripped a single 275 kV transmission line and a double circuit 275 kV line. This resulted in six voltage dips over a two-minute period on the South Australia grid, causing wind farms to enter into successive fault ride-through operations and subsequent reduction output of 456 MW over a period of less than seven seconds. The generation reduction resulted in imports of nearly 900 MW, exceeding the 650 MW limit, tripping the interconnector and islanding South Australia from the rest of the system. **Figure B.3** shows the transient and sustained power reductions from the wind plants during the sequence of events.

[48] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2016/fpss---progress-report-august-2016.pdf?la=en&hash=1AE20E2390955133309265122E2877F33

[49] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx.

[50] https://www.aemc.gov.au/sites/default/files/content//NER-v77-Chapter-04.PDF

[51] Note that the nominal frequency in the Australian power system is 50 Hz.

[52] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

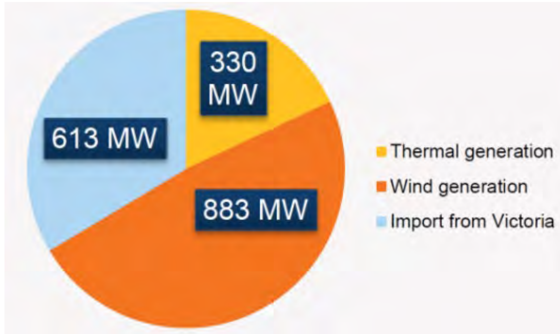

Figure B.2: South Australia Generation Mix Pre-Event [Source: AEMO]

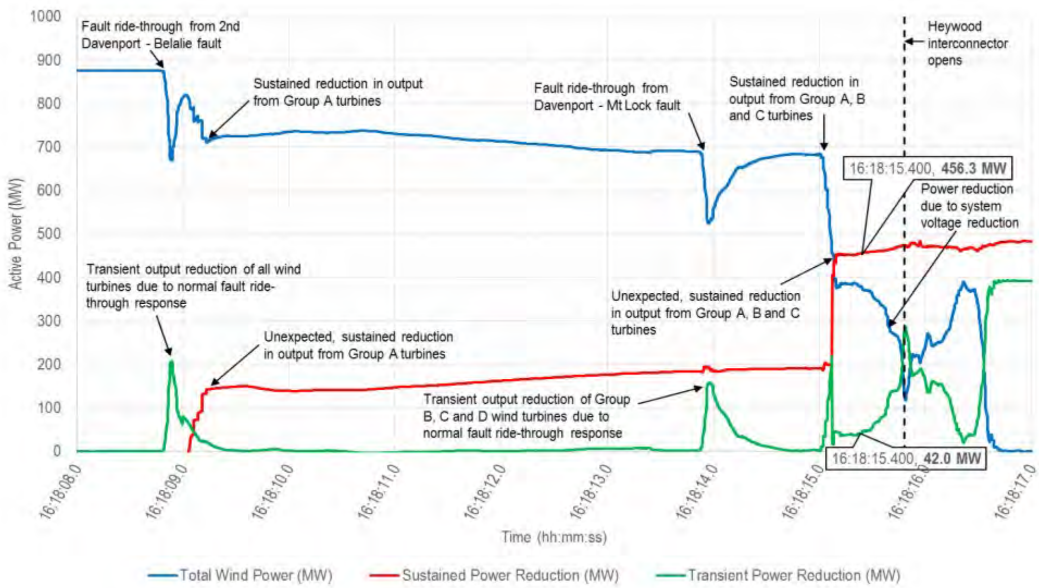

Figure B.3: Sustained vs. Transient Power Reduction of Wind Plants during September 28, 2016 AEMO Disturbance [Source: AEMO]

According to AEMO, ROCOF following separation of the South Australian system was 6.25 Hz/s (see Figure B.4), “too great for the UFLS scheme to operate effectively” as had been identified a month earlier. AEMO explained that the primary reason for frequency instability “was that, in the absence of any substantial load shedding, the remaining synchronous generators and wind farms were unable to maintain the islanded system frequency.” The absence of inertial support and resulting high ROCOF caused by an unexpected large contingency event in South Australia caused the UFLS scheme to not operate.

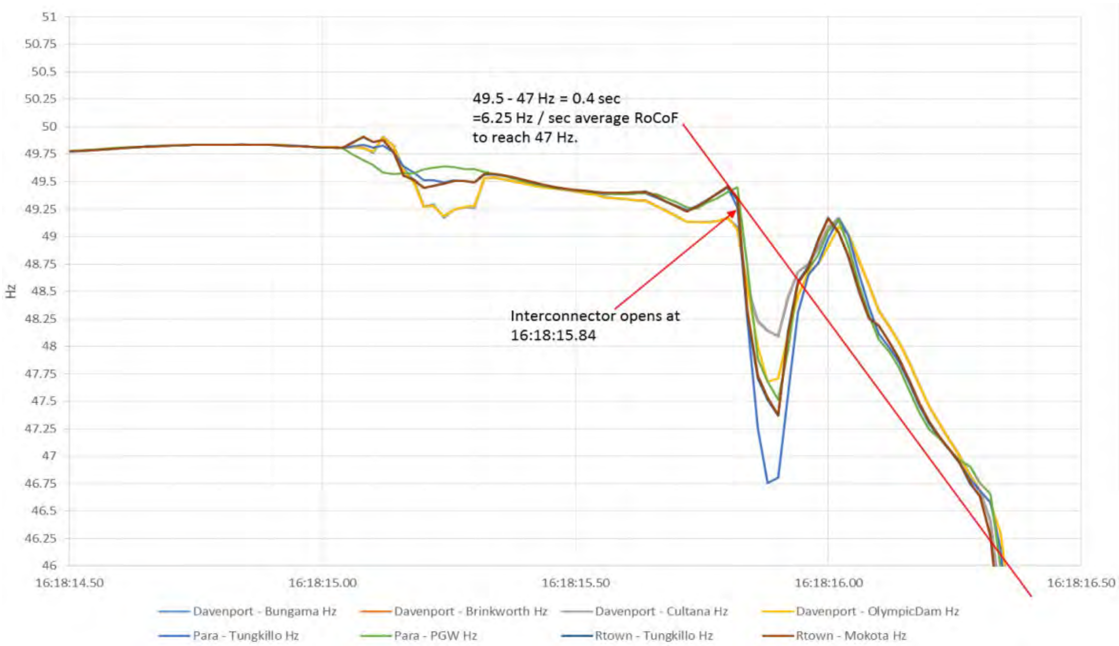

Figure B.4: Frequency and ROCOF in Various SA Nodes Immediately Before the System Separation [Source: AEMO]

After the blackout, AEMO identified a need for "sufficient inertia to slow down the [ROCOF] and enable automatic load shedding to stabilize the island system in the first few seconds." They have since implemented restrictions on the interconnector flow to ensure its loss (the largest expected contingency) does not result in a ROCOF exceeding 3 Hz/s. They have also created a minimum requirement for the number of on-line synchronous generators as they face critical inertia levels to support existing fast frequency response and primary frequency response capabilities.

Since this event, AEMO has begun a comprehensive work on UFLS specifically looking into the impacts of DER. Figure B.4 demonstrates at a high level their emphasis on the importance to account for DER in under-frequency events. The the net load disconnected from the system can vary depending on if the DER disconnects during the under-frequency event, worsening the frequency performance. As a result of their efforts, AEMO has implemented new network constraints to limit contingency sizes related to separation events in periods where the capabilities of UFLS to arrest system frequency are low. AEMO has also actively pursued a dynamic arming scheme to selectively disarm UFLS circuits with reverse flows in real time.[53]

[53] AEMO's work on this topic can be found here and here

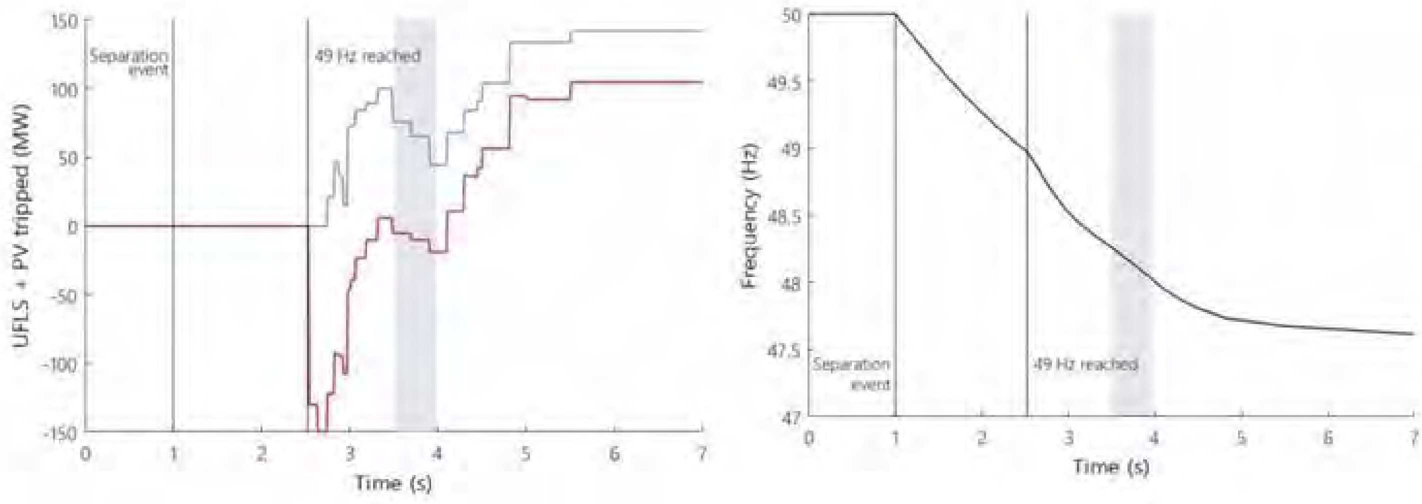

Figure B.5 Example of UFLS Operation During a Period with High Distributed PV Generation [Source: AEMO]

The South Australia experience demonstrates the importance of studying the impacts that decreasing system inertia can have on ROCOF and system frequency stability. While this example does not include DERs, DERs can and will contribute to decreasing system inertia. AEMO recently identified the importance of accounting for high levels of DERs in UFLS scheme design, suggesting the use of new "smart UFLS devices" like electric vehicles.[54]

System planning studies will need to ensure DERs are appropriately modeled such that their impact on system inertia can be appropriately captured. Inaccurate assumptions of sufficient inertial response can yield inaccurate simulation results of island-level performance during large underfrequency events. Therefore, PCs should ensure that off-peak demand conditions are also studied where local island system inertia may be at its lowest and ROCOF may be at its highest expected levels.

[54] http://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

Appendix C: Hawaii Electric Light Case Study – Adaptive UFLS

Hawaiʻi Electric Light (HELCO) has seen rapid adoption of DERs across its service territory on Hawaiʻi Island.[55] From 2011 to September 2019, the aggregate gross nameplate capacity of solar PV DERs in HELCO's service territory surged from 10 MW to 101 MW (see **Figure C.2**). The total nameplate capacity of DERs on Hawaiʻi Island is now twice as large as any other single generator on the Island, and nearly 50 percent of HELCO's historical peak load of 191 MW. The highest instantaneous penetration of DERs serving end-use load experienced by HELCO to-date is estimated to be in the excess of 80 MW. **Figure C.2** shows the widening range (greater variability) of average February net loads on Hawaiʻi Island's from 2011 to 2018.

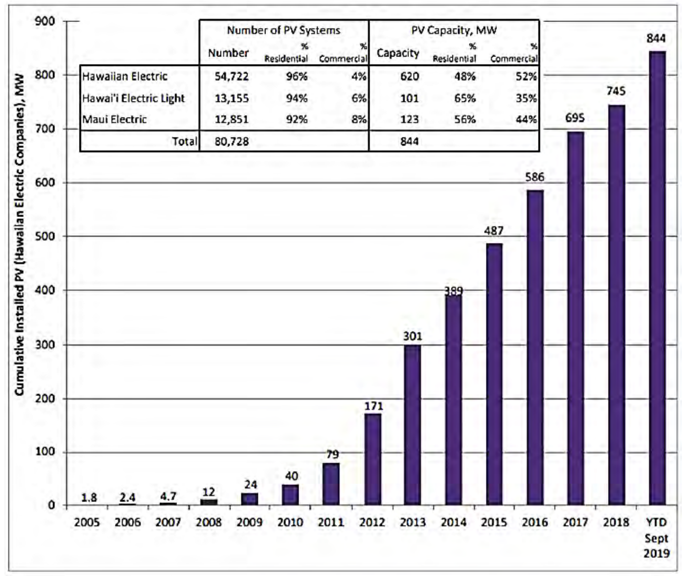

Figure C.1: Solar PV DER Growth across HELCO [Source: HELCO]

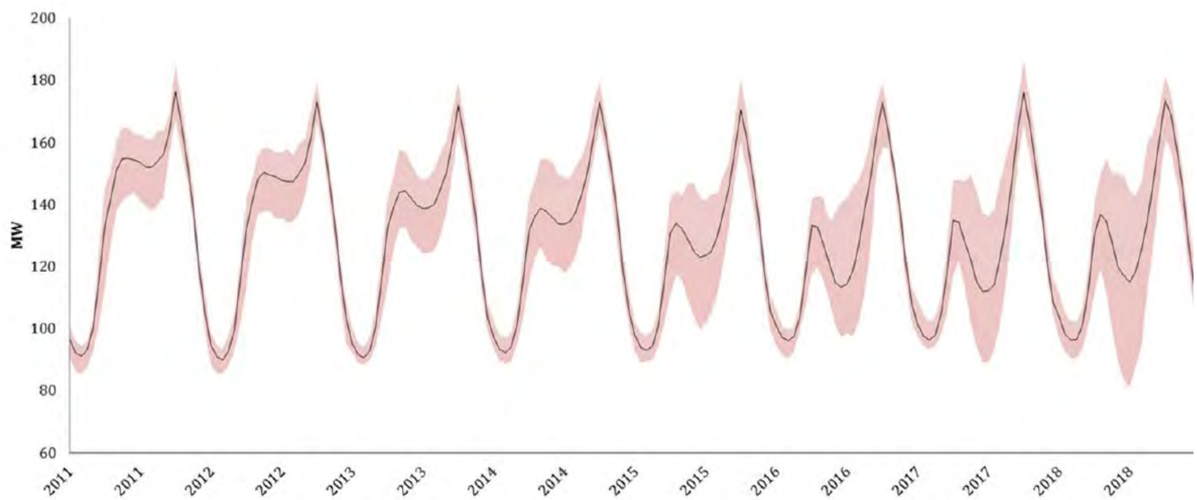

Figure C.2: Impact of DER on Hawaiʻi Island's February Average Daily (Net) Load [Source: HELCO]

As an islanded network, balancing supply and demand on Hawaiʻi Island has proven challenging, and HELCO currently relies on UFLS for a portion of its contingency reserves. Under high levels of DER penetration, reliable operation of its UFLS to maintain operation of the overall network during large power imbalances has been compromised. In 2014, HELCO conducted an initial study that determined its UFLS scheme was at risk of over-shedding load relative to the necessary amount of per the specified requirements, leading to potential overfrequency conditions. The static UFLS scheme in use at the time was set to shed blocks of predetermined net load at the feeder-level based up the historical amount of load on the circuit. The assumption in the static scheme was that the amount of load on the circuits in the

[55] R. Quint, et al., "Transformation of the Grid: The Impact of Distributed Energy Resources on Bulk Power Systems," IEEE Power and Energy Magazine, vol. 16, iss. 6, pp. 35-45, October 2019. Available here

blocks generally matched the total system demand. However, this is no longer the case with increasing penetrations of DERs.

Net loading on each feeder is influenced by the amount of DER production, and feeders may even be exporting power to the system during many parts of the day. Tripping these feeders would result in additional loss of net energy. Further, the behavior of legacy DER installed prior to current interconnection requirements places additional considerations needed on UFLS program design. The loss of aggregate DERs at legacy frequency trip settings of 59.3 Hz adds to the net energy loss during underfrequency events and exacerbates the loss of generation contingencies. On the other hand, a larger portion of legacy DERs may also trip for high frequency conditions at 60.5 Hz. This could pose risks of DER tripping exceeding the largest single generator contingency. Due to the increased risks of overfrequency, a critical aspect of the UFLS design is now avoiding over-shedding of load and reaching the 60.5 Hz trip point for the larger portion of legacy DERs.

Recognizing that the development and installation of the new UFLS scheme would take time, the static UFLS scheme was modified to reduce the possibility of over-shedding load by creating an additional load shed block and reducing the load in each block. In addition, circuits that had been included in a both an instantaneous stage and a delayed (“kicker”) stage, were assigned to only one stage to ensure even if the instantaneous stages operated to stabilize frequency for the initial disturbance the load in the delayed stages would still be retained if needed to return the frequency to 60 Hz..

Due to the rapid growth of solar PV DERs, HELCO identified a need for dynamic assignment of circuits to the UFLS scheme in real-time operations. The widespread variation of net load due to variability of DER output across the distribution system caused HELCO to re-evaluate the ability of a static UFLS program. In 2015, HELCO studied how an “adaptive” UFLS scheme might serve both to target load shed from distribution circuits with variable net load throughout the day, as well as to rapidly detect whether load shed is required on its system. Study results pointed to necessary changes to the static scheme to avoid over-shedding and under-shedding during different operating conditions. It was determined that HELCO would need to develop a custom application for an adaptive UFLS scheme to reflect both the amount of load shedding required and then dynamically assign circuits to the scheme stages. The application calculates the required amount of net demand required to be shed in real-time based on telemetered values from each distribution feeder circuit. Then, distribution circuits are automatically assigned to the underfrequency trip settings through communication to distribution circuit underfrequency relays. Further, HELCO determined that UFLS operations based on ROCOF may be required in addition to the frequency trip settings, and have planned to implement this feature in the future based on system needs. In all, over 40 substations required relay upgrades and real-time automatic controller installations. Around 78% of the distribution circuits, accounting for 70% of peak load, needed to be included in the scheme for its effective operation. Based on the urgency of the problem at hand, HELCO implemented the adaptive UFLS scheme in December 2017.

Settings for HELCO’s adaptive UFLS program are shown in **Table C.1**, including the frequency and ROCOF trip settings, the percentage of net system demand to be tripped at each stage, and the expected time of operation after the threshold is passed.

Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO]

Stage	Setting [Hz]	% of Net System Demand [MW]	Time
df/dt*	0.5/sec	15%	9 cycle relay plus breaker time
1	59.1	5%	8 cycle relay plus breaker time
2	58.8	10%	8 cycle relay plus breaker time
3	58.5	10%	8 cycle relay plus breaker time
4	58.2	15%	8 cycle relay plus breaker time

Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO]

Stage	Setting [Hz]	% of Net System Demand [MW]	Time
5	57.9	10%	8 cycle relay plus breaker time
6	57.6	20%	8 cycle relay plus breaker time
Kicker 1a	59.3	5%	10 seconds
Kicker 1b	59.5		30 seconds
Kicker 2	59.5	5%	20 seconds

Stage 1 and stage 2 should sum to 15% of total system net load (maximum allowed load shedding for N-1 unit trips).
Stage 1 through stage 4 should sum to 40% of total system net load (maximum allowed load shedding for N-1-1 unit contingencies).
*Not currently active.

The program settings are static; however, they are based on the total net system demand that is continuously fluctuating. The allocation of distribution circuits to arm at any given time is dynamic and adapts to changing system conditions. The adaptive UFLS scheme selects which distribution circuits using a priority order, consisting of four categories:

1. Normal circuit (no tripping restrictions)
2. Restricted circuit (avoid tripping if possible)
3. Highly restricted circuit (last resort for tripping)
4. Not participating (do not trip)

Each distribution circuit is then assigned to blocks based on a participation factor of one through nine (see Table C.2), determined using additional factors like whether a circuit has a "hot line tag"[56] and how many times it has previously been tripped as part of UFLS operations.

Table C.2: Customer Participation Prioritization [Source: HELCO]

Customer Priority	Priority Description	Participation
1	Normal circuit (no tripping restrictions)	1
		2
		3
2	Restricted circuit (avoid tripping if possible)	4
		5
		6
3	Highly restricted circuit (last resort for tripping)	7
		8
		9
4	Does not participate (do not trip)	10

After calculating MW targets for each UFLS stage based on the calculated total system net load in real-time, the energy management system assigns distribution circuits to UFLS stages to achieve the required MW load shed targets. Figure C.3 shows a summary display used in the HELCO EMS adaptive UFLS scheme.

[56] Which blocks remote reclosing, should the circuit be tripped.

UFLS STAGE DATA

System Load: 141.853
Total Target: 112.185
Total Available: 114.292

Stage	Frequency	Percent	Target MW	Avail MW	Tol %	Tolerance	Delta MW
STAGE1	59.100	5.00	7.01154	6.82032	5.000	0.351	0.191
STAGE2	58.800	10.00	14.02308	13.83560	5.000	0.701	0.187
STAGE3	58.500	10.00	14.02308	13.34422	5.000	0.701	0.679
STAGE4	58.200	15.00	21.03462	22.24468	8.000	1.683	-1.210
STAGE5	57.900	10.00	14.02308	14.21575	8.000	1.122	-0.193
STAGE6	57.600	20.00	28.04617	25.46988	25.000	7.012	2.576
KICKER1	59.500	5.00	7.01154	6.79824	8.000	0.561	0.213
KICKER2	59.300	5.00	7.01154	6.54598	8.000	0.561	0.466

Figure C.3: Summary Display of HELCO Adaptive UFLS Scheme EMS [Source: HELCO]

While the adaptive UFLS scheme has performed well against multiple events over the past few years, it has limitation including the extent of the contingencies for which it is planned for. In July 2019 an over-shedding of load occurred when a storm caused a quickly occurring n-1-1 event that disconnected a power plant while it was generating 40 MW. The sudden loss of 40 MW was outside of the planning criteria applied in designing the UFLS scheme and resulted in the highest ROCOF experienced on the system to date (in excess of 2Hz/Second) the resulting load shed of nearly all the instantaneous stages caused frequency to reach 61.0 Hz (see Figure C.4). While the storm conditions did limit the solar generation at the time a still measurable and significant loss of solar generation in certain areas of the Island was observed due to the high frequency. Had the solar generation been closer to what it is capable of the results would have been much worse. This event demonstrates that even a fairly robust UFLS design will not always prevent significantly abnormal frequencies, and with DER production becoming a potentially significant portion of on-line generation it highlights the essential importance of grid-supportive interconnection requirements for DER, including expanded ride-through capabilities and control.

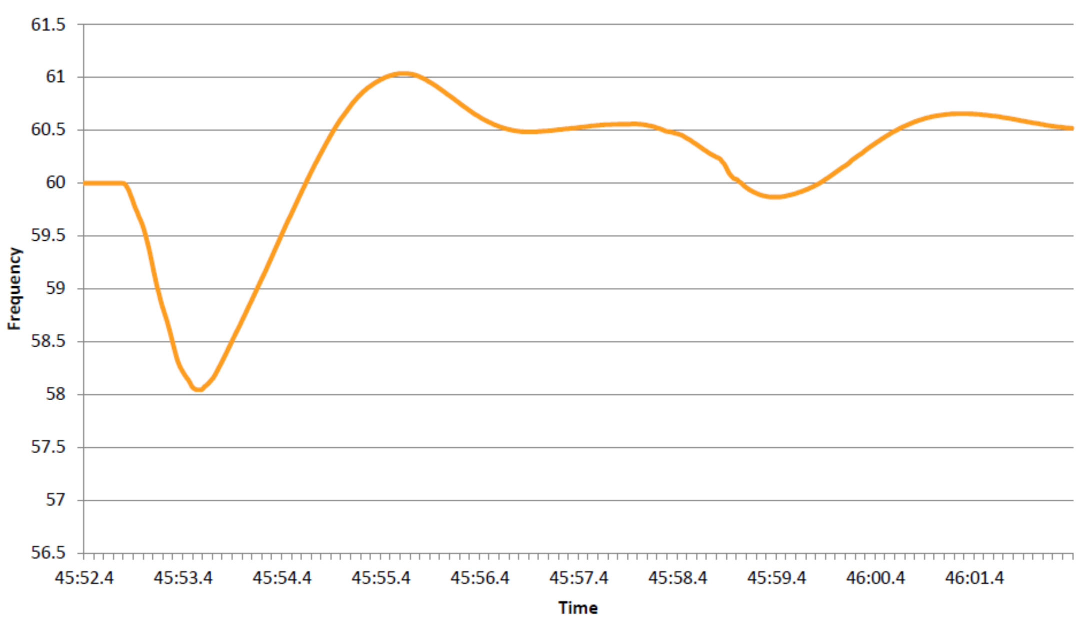

Figure C.4: July 8, 2019 UFLS Event on Hawaiʻi Island [Source: HELCO]

As a result of this event, HELCO identified additional improvements to the UFLS program including changes to UFLS block sizes, UFLS frequency thresholds, and enabling the ROCOF trip setting. The recommendation was for this to be implemented by the first quarter of 2020. In actual field implementation, it was found that the dynamic system behavior makes the ROCOF settings challenges and initial implementation resulted in a small shed during normally cleared faults.

Given that the loss of aggregate DER with legacy frequency and voltage settings remains HELCO's largest contingency, HELCO has also identified a need for FFR from energy storage resources to reduce the incidence and impact of UFLS load shed. This FFR is procured through competitive bid.[57] The FFR storage resource is sized according to HELCO's resource plans and the level of aggregate DER with legacy trip settings. The resource providing this service is required to have configurable parameters, a proportional response to changes in frequency outside a pre-defined deadband, have capability to respond to over- and under-frequency events, and be able to maintain established state of charge. HELCO is presently managing the increasing amounts of variable, inverter-based resources (particularly DERs) by procuring sufficient amounts of operating reserves and grid flexibility.

HELCO's experience with studying and implementing an adaptive UFLS scheme will prove invaluable to entities across North America as the BPS is faced with higher levels of aggregate DERs in the future.

57 https://www.hawaiielectriclight.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20190822_final_stage_2_hawaii_variable_rfp.pdf

Appendix D: Impacts of DERs on ISO-NE UFLS Islanding Study

Driven by state policies and private investments, DERs have steadily grown in the ISO New England (ISO-NE) region. As of December 2018, there were over 157,000 solar PV DERs in ISO New England under 5 MW, with the vast majority under 25 kW installations, representing a total of 2,884 MW (see **Figure D.1**).[58] State-level distribution of solar PV DERs in ISO-NE in 2018 is shown in **Table D.1** Massachusetts constitutes about 65% of the total installed solar PV capacity in the New England region. The 2019 ISO-NE solar PV DER forecast indicates a much faster growth of solar PV installations across the New England region in the coming years. **Figure D.2** illustrates ISO-NE's solar PV forecasts and how existing integration of DERs has far exceeded forecasts over the past five years.

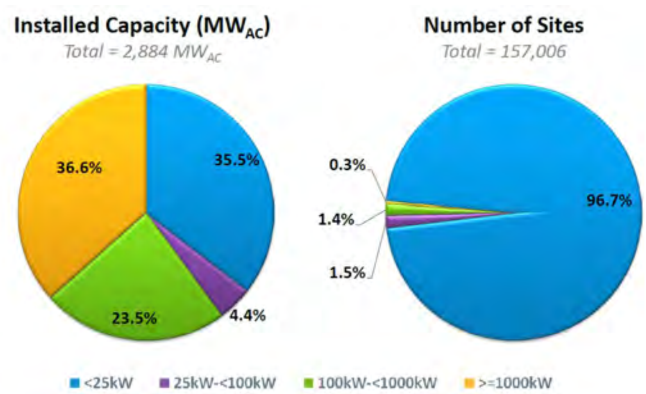

Figure D.1: Installed Solar PV Capacity as of December 2018 in ISO-NE [Source: ISO-NE]

Table D.1: 2018 Solar PV DERs in ISO-NE, by State [Source: ISO-NE]		
State	**Installed Capacity (MW)**	**Number of Installations**
Massachusetts	1,871	90,720
Connecticut	464	35,889
Vermont	306	11,864
New Hampshire	84	8,231
Rhode Island	117	5,993
Maine	42	4,309
New England	**2884**	**157,006**

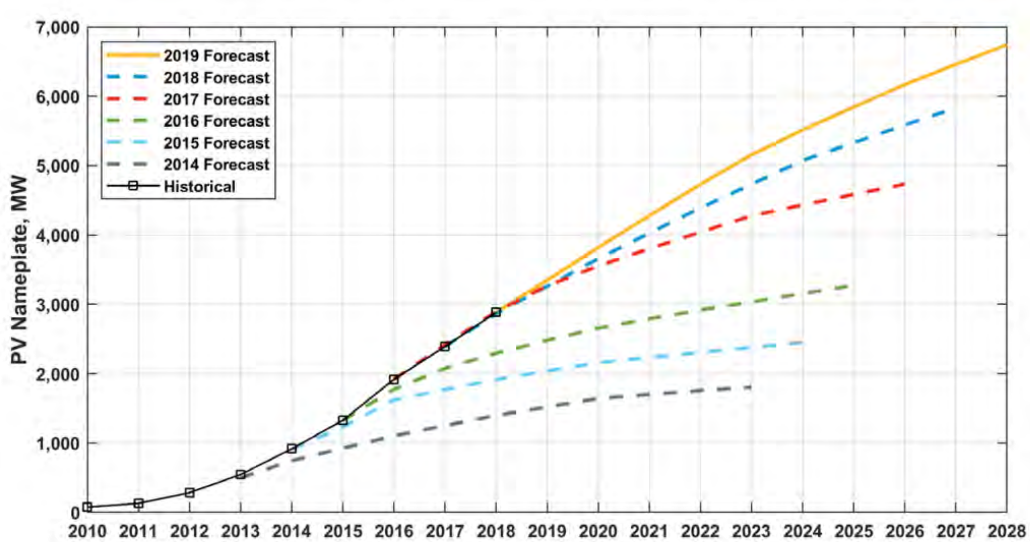

Figure D.2: Reported vs. Forecasted Solar PV DER Growth [Source: ISO-NE]

58 ISO New England Final 2019 PV Forecast: https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf

ISO-NE does not have direct visibility of the location or output of DERs since the majority of these resources do not participate in the ISO-NE wholesale markets. Nevertheless, ISO-NE has observed how DERs (in aggregate) have reduced system net load and even shifted the system peak load in some cases. As an illustrative example (see **Figure D.3**), ISO-NE reconstituted the total expected gross load on its system by adding the expected level of DER output to the measured net load for a peak summer day in 2018. On this day, the peak net load (red square) of approximately 26,000 MW was not only lower than the peak gross load (green circle) of approximately 27,000 MW, but it also shifted the net peak load time from 3 PM local time to 5 PM local time.[59] Given the projected growth of aggregate DER projected in the ISO-NE 2019 solar PV forecast, it is important to understand the increasing penetration of DERs in the ISO-NE footprint and the potential impacts this can have on BPS performance (particularly during underfrequency disturbances).[60]

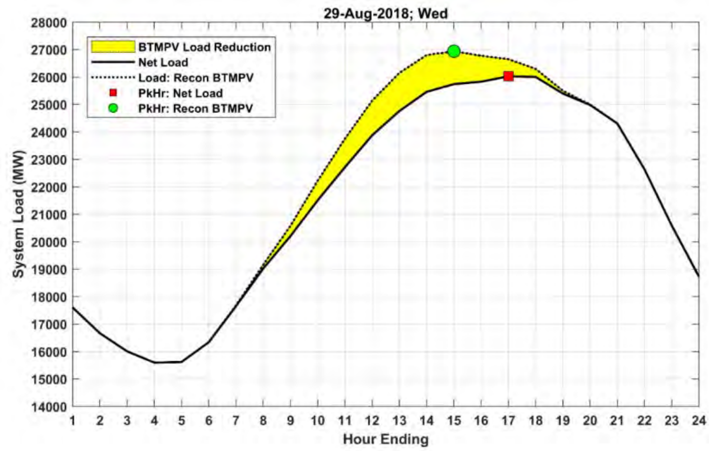

Figure D.3: Solar PV DER Offsetting Net System Load during Summer Peak – August 29, 2018 [Source: ISO-NE]

NPCC UFLS Program

The Northeast Power Coordinating Council (NPCC) Directory-12[61] describes the implementation plan for UFLS programs in the NPCC region. Upon the adoption of PRC-006-NPCC-02, NPCC intends to reture Reliability Direction 12 in accordance with NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study. **Table D.2** shows the stages of UFLS operation, the percentage size of each UFLS tripping block, and operating times for load shedding actions. The NPCC UFLS program consists of five stages, with four stages having about 7 percent of load shed at each stage. The fifth stage is an anti-stall stage which sheds additional 2 percent load if the island frequency is below 59.5 Hz for more than 10 seconds.

Table D.2: NPCC UFLS Program [Source: NPCC]

Stage	Threshold Setting [Hz]	Tripping Block Size [%]	Cumulative Load Shed [% of TO or DP Load]	Total Operating Time [s]
1	59.5	6.5–7.5	6.5–7.5	0.3
2	59.3	6.5–7.5	13.5–14.5	0.3
3	59.1	6.5–7.5	20.5–21.5	0.3
4	58.9	6.5–7.5	27.5–28.5	0.3
5*	59.5	2–3	29.5–31.5	10

Note: Total operating time is the load-weighted average for all load within a Balancing Authority area, with maximum deviation for any load limited to ± 50 ms.
* Anti-stall

[59] https://www.iso-ne.com/static-assets/documents/2019/03/a4_draft_2019_isone_annual_energy_and_summer_peak_forecast.pdf
[60] The results shown in this section do not represent the official results of ISO-NE as studies similar to this are being performed by SS-38 NPCC working group. However, the results do highlight some of the concerns that may need to be addressed with increasing DER penetration.
[61] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

UFLS Program Design Studies Incorporating DERs

ISO-NE used a 2023 Summer Peak base case with ISO-NE gross load of 28,176 MW and 5,200 MW of DERs. Following DER modeling guidelines,[62] DERs were modeled as either R-DERs or U-DERs in the power flow base case. 2,200 MW were represented as R-DERs and 3,000 MW were represented as U-DERs. The load bus in the power flow base case was converted to six feeders, five feeders with R-DER resources and one feeder with U-DER resources (see **Figure D.4**). Key modeling assumptions were made:

- R-DERs are installed throughout the distribution system near the end-use loads and are located on feeders that may have UFLS relays. During underfrequency conditions, UFLS relays will trip feeders that include end-use load and R-DERs. End-use load and any co-located R-DERs are modeled to trip consistent with NPCC Directory-12 frequency set points and load shed requirements (per **Table D.2**).
- R-DERs are evenly split among the feeders, which was deemed a reasonable assumption since the objective of the study is to understand the impact of DERs on an islanded ISO-NE system; therefore, the distribution of DERs among feeders is not of concern.
- U-DERs are modeled separately from the R-DERs so that they can be differentiated from any DERs that may be tripped by the UFLS relays. U-DERs are not located on the distribution feeders, and therefore would not trip during operation of the UFLS relays.
- DERs are assumed to be compliant with IEEE 1547-2018, and assumed to meet the ISO-NE Source Requirements Document (SRD)[63] establishing DER settings requirements within the ISO-NE footprint (see **Figure D.5**).
- DER models are implemented as following:
  - R-DERs are modeled using REGC_A and REEC_A dynamic models; voltage control is not used; constant real and reactive power mode (unity power factor) is assumed; and voltage and frequency tripping are modeled (see **Figure D.5**). Please note that R-DER trip along with the UFLS. The frequency settings are the same as the UFLS set points. This is to simulate the tripping of load and DER at the same time. In PSS/E version 33.12.1, the load and the DER cannot be modeled as a single composite load as in version 34 and above and hence the two components were split.
  - U-DERs are modeled using REGC_A, REEC_A, and REPC_A dynamic models; voltage control is included; plant controls are included; and voltage tripping is modeled (see **Figure D.5**).
    - Frequency trip settings for U-DER are much lower than the NPCC UFLS set points shown in **Table D.2** and have longer trip times; therefore, frequency tripping of U-DERs is not been included. Please note that R-DER are part of the load and hence would trip with the load. The U-DER are separate and their frequency timer settings are more than the UFLS set points. For example, at 58.5 Hz, the trip setting is 300 seconds. The simulation is run for 60 seconds only before which the frequency has to go above 59.5 Hz. So U-DER frequency tripping has not been included.
  - Second generation renewable models were used at the time of study due to an implementation issue in the DER_A model, which has currently been resolved. Previous SPIDERWG reliability guidance on the choice of dynamic models representing aggregate DER should still be used when performing such studies.

[62] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[63] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

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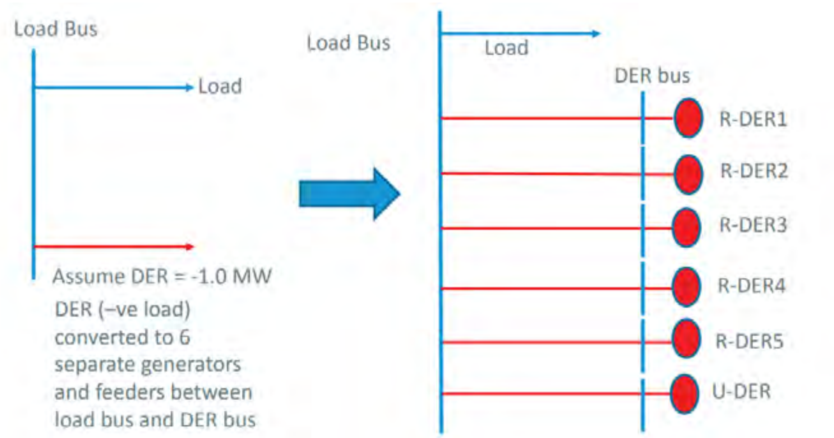

Figure D.4: DER Modeling in Power Flow [Source: ISO-NE]

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Figure D.5: Voltage and Frequency Trip Settings for DERs – ISO-NE SRD Requirements [Source: ISO-NE]

Figure D.6 below shows the percentage of R-DER tripped and its associated frequency trip points. These percentages have been applied to all R-DER in the load flow case. The frequency trip settings for R-DER correspond with the UFLS program settings. This has been done to simulate the tripping of load as well as R-DER at the set points as dictated by the UFLS program.

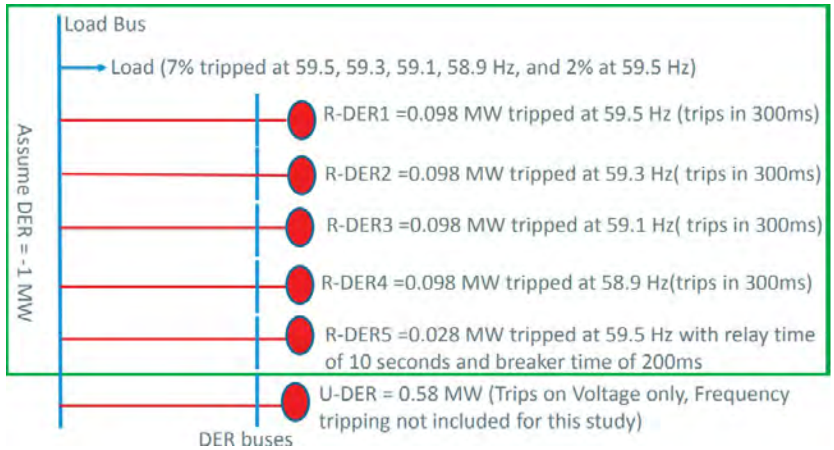

Figure D.6: Load Shed and Assumed Split of R-DER and U-DER with trip settings

Impact of R-DER on Deficiency Calculations per PRC-006

ISO-NE assumes that DERs are evenly distributed across its system, which is deemed a practical modeling assumption for R-DER and U-DER since PRC-006 focuses on an electrical island-level impact. The UFLS program must meet specific underfrequency performance requirements caused by an imbalance defined as:

$$Imbalance = \frac{Load - Actual\ Generation\ Output}{Load}, of\ up\ to\ 25\%\ within\ the\ identified\ island(s)$$

As described in Chapter 2, if "load" is assumed as net demand, then the deficiency for analyzing the 2023 Summer Peak scenario would be 25% of 25,976 MW (28,176 MW of gross load minus 2,200 MW of R-DER), or 6,494 MW. If "load" is assumed as gross demand, then the deficiency would be 25 percent of 28,176 MW, or 7,044 MW. **Figure D.7** shows the electrical island frequency response for a simulated deficiency of each scenario. The simulation clearly shows that using gross load results in a deeper frequency nadir and a slower recovery in frequency (due to a larger deficiency). Further, the simulations here show that if ISO-NE used the 25% imbalance based on net demand, it would be compliant with the UFLS program requirements; however, assuming a 25% deficiency based on gross demand would result in simulations that do not meet the performance calculations (and additional load shedding would be required).

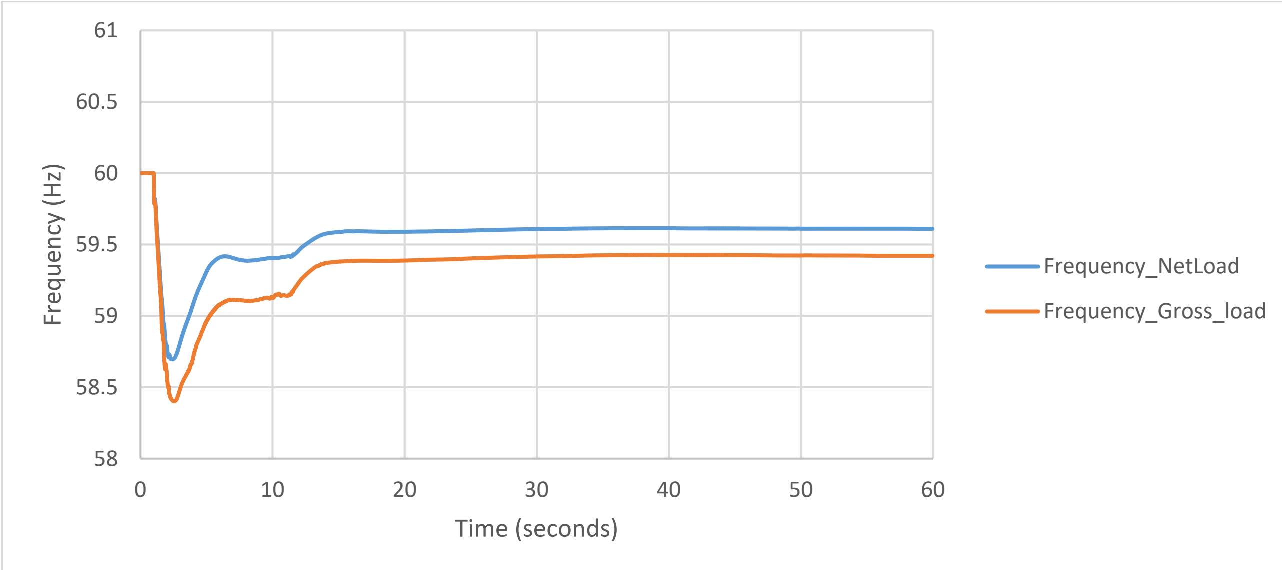

Figure D.7: Net Load versus Gross Load

Tripping of U-DER Due to Voltage Fluctuations

Subsequent to frequency recovering above 59.5 Hz, the loss of load due to UFLS action causes the bus voltages to rise to a level and for a duration that may exceed the trip settings of U-DER causing U-DERs to trip. Figure D.8 below shows the bus voltages at a U-DER location causing it to trip on voltage trip settings. The bus voltage exceeded 1.1 pu for more than 2 seconds and based on *Inverter Source Requirement Document of ISO New England (ISO-NE)*[64] Table-1 settings, U-DER tripped.

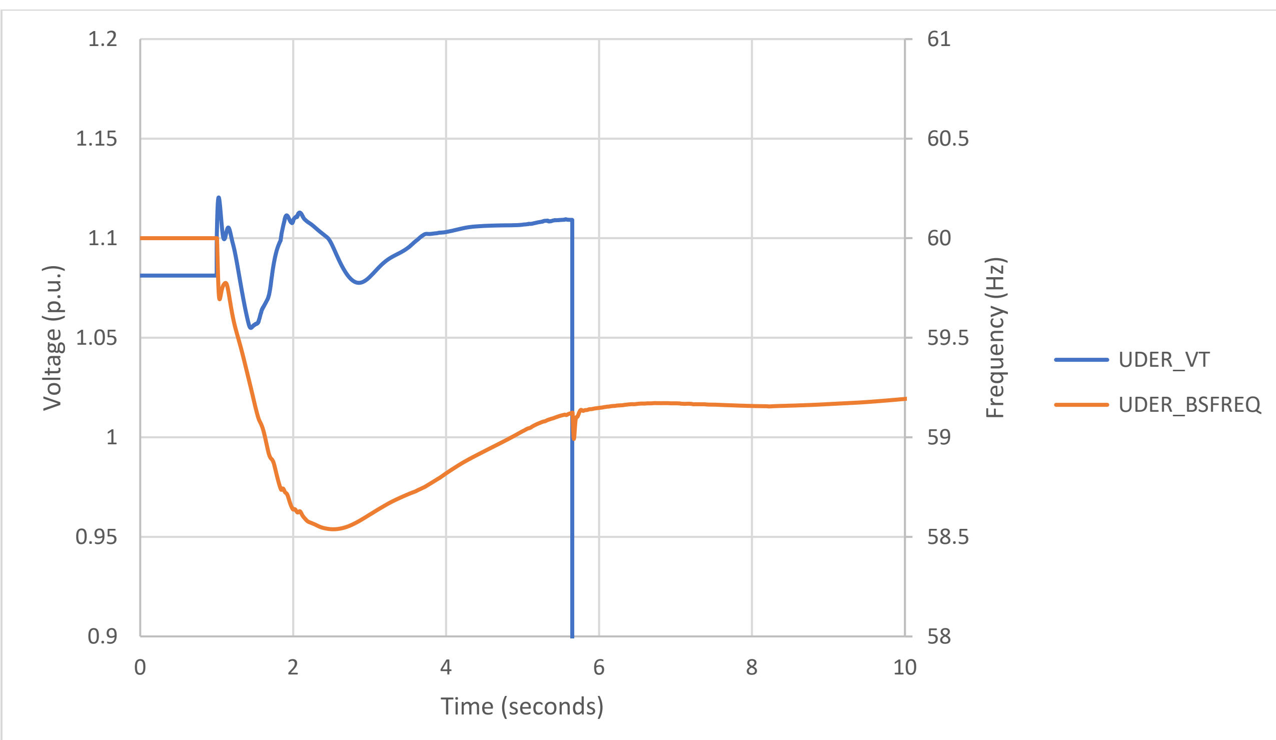

Figure D.8: U-DER Tripping on Voltage Due to UFLS

[64] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

The loss of U-DER due to voltage trip settings further adds to the island generation deficiency. It is quite possible that due to this additional generation deficiency the island frequency may not recover above 59.5 Hz and hence may violate the criteria as shown in **Figure D.9** below.

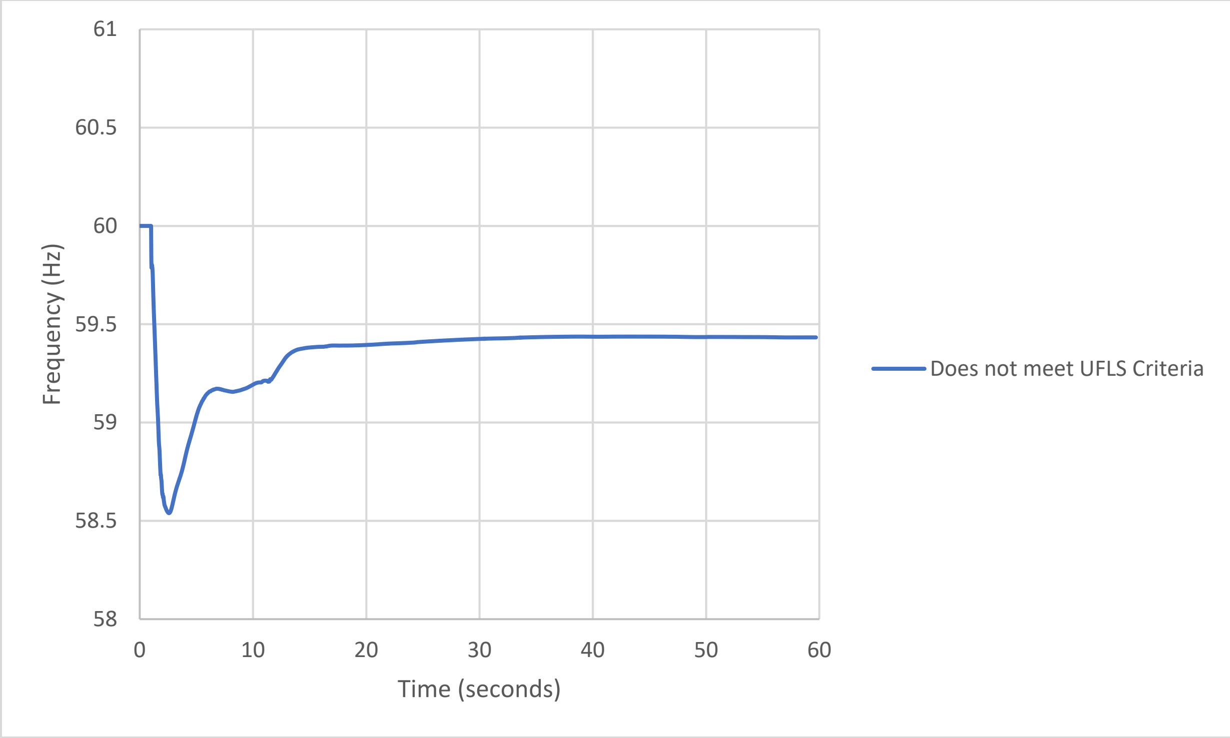

Figure D.9: ISO New England Island Frequency Performance Relative to NPCC Directory #12

UFLS Program Design with DER Impacts

High penetration of DERs in the system may require compensatory load shedding to make up for the loss of DERs during under frequency conditions. Under NPCC Directory-12 requirements, generating units shall not trip for under frequency conditions in the area above the curve as shown in **Figure D.10** below.

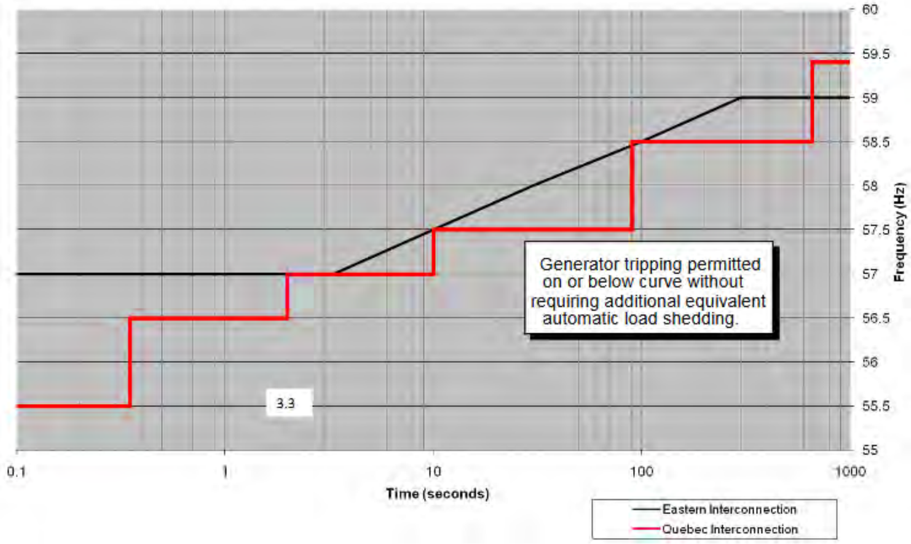

Figure D.10: Standards for Setting Underfrequency Trip Protection for Generators

If one considers the total R-DER that trips above the black curve in **Figure D.10** as a single aggregated unit, then additional compensatory load shedding may be needed to cover for the loss of R-DER. Including an additional compensatory load shedding percentage to cover for the loss of R-DER helps the island frequency to recover above 59.5 Hz and makes the UFLS program compliant. **Figure D.11** below shows the island frequency with compensatory load shedding.

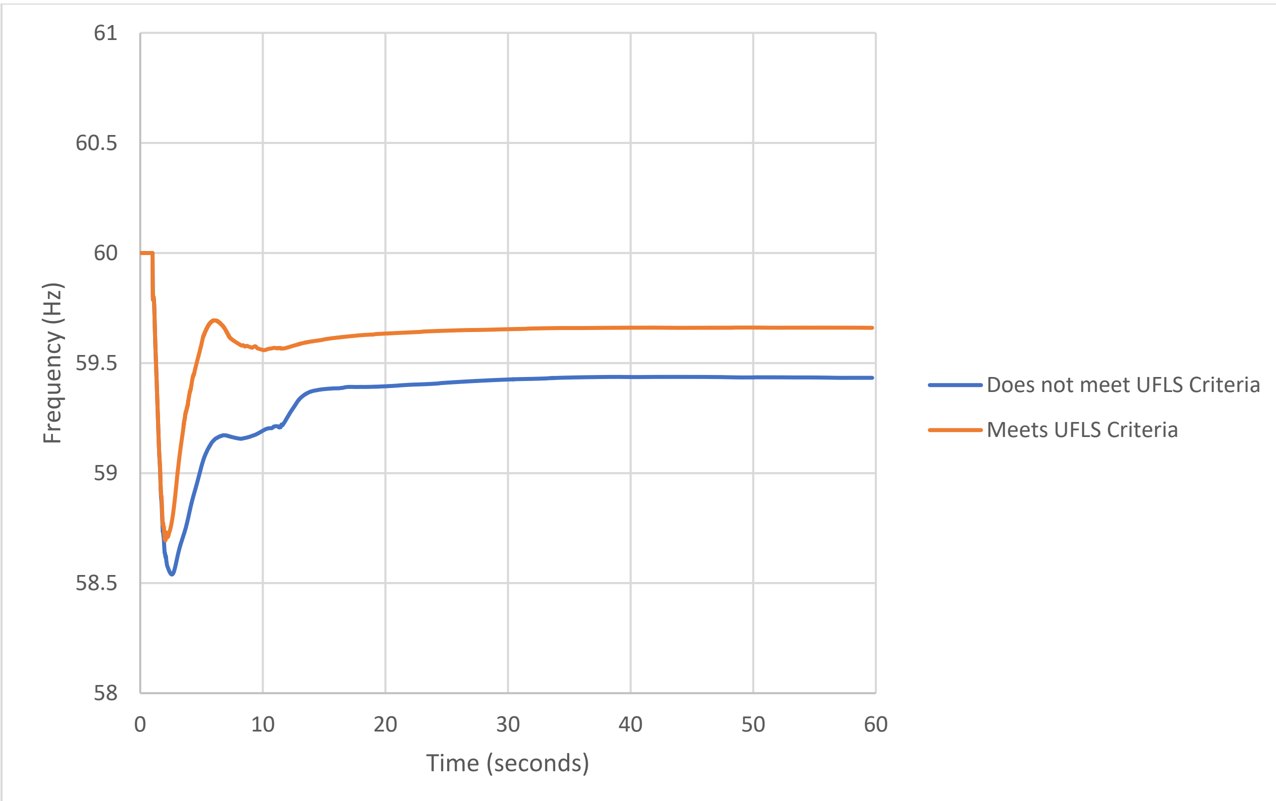

Figure D.11: ISO New England Island Frequency with Compensatory Load Shedding

Contributors

NERC acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC SPIDERWG.

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SPIDERWG Presentation on the Modeling Survey

Action

Information

Summary

The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices. The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Survey of DER Modeling Practices

NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) - White Paper

February 2021

RELIABILITY | RESILIENCE | SECURITY




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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Executive Summary

The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices.[1] The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

Key Findings

The following key findings were identified from this survey:

- **Questions 2 and 3:** Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.
- **Question 5:** Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.
- **Question 6:** Forecasted DER penetration levels are likely to increase in the coming years, particularly in the planning horizon. Responses shifted towards increased penetration levels by 2024. 16% of respondents, however, did not have a DER forecast out to 2024.
- **Question 7:** 40% of respondents reported observing DER tripping during fault events on the electrical grid. Few entities were able to report a quantitative amount of DER tripping due to limited data available.
- **Question 8:** 40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon. Shifts in peak or light net load hours has an impact on the planning assumptions used for BPS reliability assessments, which impacts how NERC TPL-001 reliability studies are executed.
- **Question 9:** About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner.
- **Question 10:** 45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no explicit dynamic behavior representation of DER in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.
- **Question 11:** About 50% of respondents do not have a threshold for modeling utility-scale DERs (U-DERs), i.e., larger DERs that are three-phase installations, and do not model U-DERs in their studies. The remaining respondents use some threshold ranging from less than 1 MW to above 10 MW.

[1] For this survey and its results, distributed energy resources are defined as "any source of electric power located on the distribution system," as defined in the NERC SPIDERWG Terms and Definitions Working Document: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document%20rev%201.docx.pdf

- **Question 12:** 62% of respondents stated that they do not model retail-scale DER (R-DER) to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.
- **Question 13:** Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.
- **Question 14:** 73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.
- **Question 15:** Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.
- **Questions 16 and 17:** About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage. For those that do model distributed energy storage, about 70% stated that they model both full injection and full absorption scenarios; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

Recommendations and Next Steps

The survey highlights that DER penetrations are rising yet DER data collection, modeling, and modeling practices need to improve across the industry. SPIDERWG will continue to support industry education of DER modeling and studying their impacts to BPS reliability through workshops, webinars, guidelines, and technical reports. SPIDERWG recommends the following to all TPs and PCs to improve DER modeling practices:

1. **TPs and PCs with minimal DER penetration:** TPs and PCs with minimal levels of DERs should continue monitoring DER forecasts and be prepared to incorporate DER models explicitly into planning assessments to understand their potential impacts to BPS reliability for steady-state and dynamic studies. Regardless of DER penetration level, all entities should ensure that DER tracking and data collection is in place such that the penetration of DERs can be accounted for in studies and forecasts appropriately.
2. **TPs and PCs with DER penetrations but lack of available DER modeling information:** TPs and PCs in this situation should incorporate the recommendation in NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*,[2] and work with their respective Distribution Providers to ensure that DER information is collected and made available for the purposes of BPS reliability studies. Without sufficient information regarding DER penetration levels, TPs and PCs cannot execute accurate reliability assessments in the planning horizon. Distribution Providers are strongly recommended to review NERC *Reliability Guideline: Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*[3] and ensure DER data is being collected and provided to the TP and PC for the purposes of BPS planning assessments.
3. **TPs and PCs seeking guidance for recommended DER modeling practices:** All TPs and PCs should review the recommendations provided in NERC reliability guidelines[4] pertaining to recommended DER modeling practices, and improve their modeling capabilities for representing aggregate levels of DERs. Modeling DERs is paramount to identifying any potential reliability issues that may be presented with increasing levels of DERs; hence, entities cannot assess impact with DER information and models to study those impacts.

SPIDERWG recommends that the NERC Reliability and Security Technical Committee (RSTC) should consider the current state[5] of DER modeling practices and ensure that barriers to the collection of DER information for the purposes of executing planning assessments are addressed and broken down appropriately.

[2] This document is available here
[3] This document is available here
[4] This document is available here
[5] This white paper illustrates that DERs are having an impact on the BPS, particularly tripping during fault events, and that entities are using limited or no DER modeling practices in some cases. Further, the extent of DER modeling in dynamic studies is fairly minimal considering the current and projected forecasts of DERs in many footprints. Limitations to DER modeling include lack of information regarding DER installations and limited DER modeling capability.

Introduction

Many areas of the North American bulk power system (BPS) are experiencing an increasing penetration of DERs, and this is already affecting TP and PC modeling practices and planning assessments. Representing DERs in planning assessments becomes increasingly important as the penetration of DERs rises across many TP and PC footprints. NERC SPIDERWG has developed reliability guidelines and recommendations for modeling DERs in planning assessments, and continues to support industry awareness and voluntary adoption of these recommendations. Unlike BPS elements that are often modeled explicitly, DERs are usually represented in aggregate due to the small size of individual units. While these resources are located on the distribution system, their growing impact to the BPS cannot be neglected and this is especially true in BPS planning assessments. DER models are needed to perform steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies. TPs and PCs may need information and data that enable them to develop models of aggregate DERs for planning purposes.

In addition to issuing recommendations and guidelines, SPIDERWG conducted an informal survey of its members to analyze the DER modeling practices of different entities. Understanding the different modeling practices across entities helps identify any gaps and develop a strategy for DER modeling as part of the overall reliable integration of these resources. This white paper discusses the survey questions and the results of the survey.

DER Survey Setup

The Modeling Subgroup of the NERC SPIDERWG developed and executed an informal survey of its membership. The survey questions were developed by the subgroup and reviewed by the overall SPIDERWG. The survey was specifically geared towards TPs and PCs regarding their modeling practices, and 63 entities within SPIDERWG were asked to participate. A total of 45 of those entities provided a response to the survey. At the time of the survey, the NERC Compliance Registry consists of 75 entities registered as PCs and 206 entities as TPs.[6] Some respondents did not provide completed surveys or answers to specific questions, which is believed to be due to the lack of information. Detailed descriptions of the survey setup and questions are in Appendix A.

[6] Note that the registration criteria for these types of entities is not mutually exclusive.

Chapter 1: Review and Analysis of DER Survey Responses

The section briefly describes the key findings and takeaways from the analysis of the survey results. Appendix B provides a summary of the responses to the survey questions. Information regarding specific entities' responses are withheld for confidentiality reasons. Relevant Key Findings are summarized in **Table 1.1**

Table 1.1: Key Findings from Survey Questions		
#	**Related Questions**	**Key Finding**
1	Question 6	From responses to this question and from comparison of the existing and future amounts of DER, it is seen that in the future with the DER growth, some entities will have an increase in amount of DER that will move them to a higher category. For example, currently, there are eleven entities with the DER capacity between 1000 and 5000 MW, and in the future there will be nine entities in this category. This is because for two entities, the increase in the DER will move them to the category of entities with the DER capacity larger than 5000 MW. The same is true for entities with other DER amounts.
2	Question 7	Five respondents observed widespread tripping of the DER with faults[7], none of them has provided the amounts of the DER that were tripped. Although not many of the respondents observed widespread DER tripping with faults, this may be due to lack of visibility on the distribution systems and thus, insufficient data on the DER output and tripping. Other prevailing inferences could be that faults didn't occur in their regions or that the DER penetration is so low that any trip of DER is lost in the "noise" of the response. Any of these would result in no observed widespread DER tripping.
3	Questions 16 and 17	The reasons for not modeling energy storage explicitly[8] were absence of such storage, absence or lack of data on distribution-connected energy storage, or absence of appropriate tools. The largest category of "No" responses was due to the absence of distribution-connected energy storage, followed by the category of lack of data on distribution-connected energy storage.

Based on the results of the survey, there are still not many entities that model DER, especially in dynamic stability studies. Significant number of entities model DER netted with load even if the amount of DER in the system is substantial and represents noticeable percentage of the system load. Such amount of DER would have impact on the system performance, but this impact is not considered if the DER are not modeled explicitly in the studies undertaken by TPs, PCs, and other transmission entities. With the growing penetrations of renewable resources, which is currently focused on distribution-connected growth in many electric utilities, modeling DER is becoming more important. Based on the attention to growing penetrations of DER, the SPIDERWG modeling subgroup identified categories of percentage penetration of DER based on the responses to Questions 5 and 6. These can be found in **Table 1.2**[9]. The prominent modeling practices along with the number of entities that fall into this category are also provided in **Table 1.2**.

[7] As this question was put generally, the five responses could indicate either five different faults seen by the different survey responders or it could be a single fault seen by the five different entities.

[8] Responses to the survey varied between assuming an implicit or explicit representation based on inference between the questions. Most assumed explicit representation from the survey question.

[9] One survey result did not have both Questions 5 and 6 completed, which may skew this data slightly.

Table 1.2: DER Penetration based on Questions 5 and 6

Penetration Percentage	# of Entities	Prominent Modeling Practices
Over 100 Percent	1	In this entity DERs were modeled as generators, both in power flow and in dynamic simulations
Between 50 percent and 100 percent	1	DERs were modeled as negative load due to lack of appropriate modeling tools
Between 20 percent and 50 percent	2	One entity modeled DERs as negative load, again due to lack of modeling tools. The other modeled DERs as a generator as part of the composite load. DERs were modeled with second generation renewable dynamic models.
Between 10 percent and 20 percent	11	Out of these 11 entities, three modeled all DER in power flow regardless of size, three others modeled only DER that are larger than 1 MW, two entities modeled in power flow only DER that are larger than 5 MW, one entity modeled DER larger than 10 MW, and two modeled all DER as negative load. As for dynamic simulations, five entities out of these eleven didn't model DER due of absence of data or lack of tools, and six entities modeled DER. Out of these six, five modeled DER as generators with renewable models and one modeled DER some as generators and some as a part of composite load model.
Between 5 percent and 10 percent	20	In power flow, two entities modeled all DER regardless of size, one modeled only DER that are larger than 1 MW and five modeled them as negative load. In dynamic stability, eight entities modeled DER. The explanations of that were absence of tools and absence of DER data and for some entities, that they haven't observed visible impact of the DER on transmission system that would justify modeling DER in dynamic stability. Out of these entities, two modeled DER in power flow as generators or as a part of composite load model, and the ten modeled DER as negative load. In dynamic stability, ten entities did not model DER and the other two modeled DER with the DER_A model. Not modeling DER was explained by the absence of tools, absence of DER data and negligible impact of the DER on transmission system.
Less than 1 percent	9	Out of these nine entities, seven did not model DER, and two modeled DER in power flow and stability as generators with DER_A model. The survey respondents provided the following reasons for not modeling DER: ▪ Low amount of DER in the system ▪ Lack of data on the DER locations, and their output ▪ Lack of tools to model DER ▪ Lack of knowledge of the models

Significant amount of entities reported that they observed shifting of the system peak because of the DER output. Peak shifting causes TPs and PCs to study more system conditions than the ones that were studied before, and as the current dominant DER technology is solar photovoltaic (PV), creates a need for DER models of high quality and fidelity[10]. In addition to the system peak and off-peak conditions, such conditions as net system peak when DER output is low and the system load is still high will also need to be studied[11]. These cases may represent hours 18 or 19 on summer weekdays when sun goes down, but the load is high due to air-conditioners. Off-peak system conditions with high DER output and low load, which represent spring weekend afternoons, may also appear to be critical. System conditions with high gross load and high DER output (when these conditions are coincident) may be a challenge for dynamic stability system performance because of stalling of single-phase induction motor load with faults and possible tripping of DER because of low voltages. In all these cases, adequate modeling of the DER is becoming more and more important.

This shifting of system peak because of DER output should be taken into account when attempting to correlate the responses related to Question 3 (minimum gross load) and Question 5 (DER capacity) as shown below in **Figure 1.1** Nevertheless, it is significant and important to recognize that there are many jurisdictions where the ratio of maximum DER capacity to minimum gross load is above 20 percent.

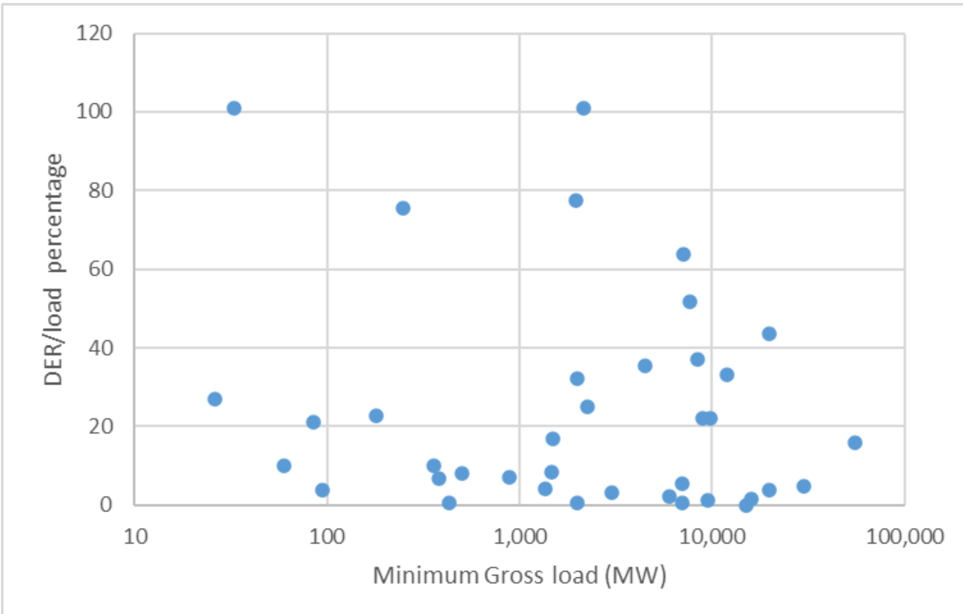
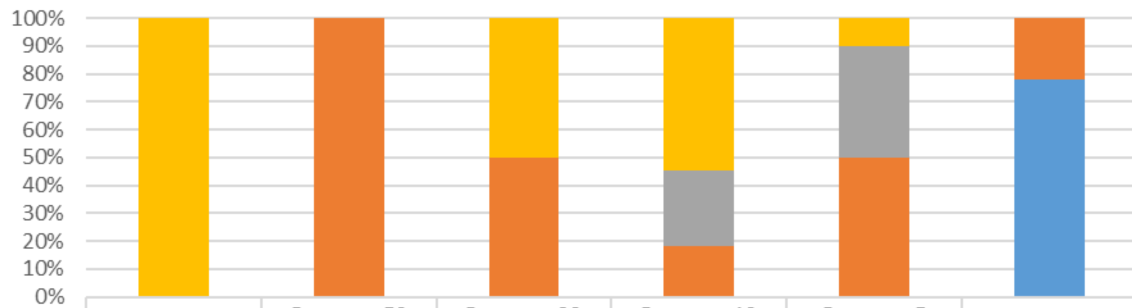


Figure 1.1: Ratio of Maximum DER capacity to Gross Minimum Load

From the results in the survey, the SPIDERWG categorized the number of entities by their modeling practices based on their penetration level in **Figure 1.2**. Entities that did not model in powerflow or dynamics were recorded as “no modeling”, entities that had powerflow models, but no dynamic models or were modeled as negative load were recorded as “limited modeling”, entities that had a dynamic record associated with the DER were recorded with “moderate modeling”, and entities that used a dynamic record modeled according to latest guidance available were recorded as “exceptional modeling”.

[10] This also applies to BPS-connected solar PV models. To reiterate, all solar PV models will need to modify their available power output based on the time of day selected for the study.

[11] This point is emphasized in “Verification Process for DER Modeling in Interconnection-wide Base Case Creation,” published in the June 2020 CIGRE journal: https://e-cigre.org/publication/CSE018-cse-018.



	Over 100 Percent	Between 50 percent and 100 percent	Between 20 percent and 50 percent	Between 10 percent and 20 percent	Between 5 percent and 10 percent	Less than 1 percent
Exceptional Modeling	1	0	1	6	2	0
Moderate Modeling	0	0	0	3	8	0
Limited Modeling	0	1	1	2	10	2
No modeling	0	0	0	0	0	7

DER Penetration Percentage

Figure 1.2: Modeling Practice Percentage by DER Penetration

Although the respondents used their best knowledge in responses to the survey questions, the responses to the question regarding total amount of the DER in the system may make conclusions of the survey to be less accurate. Since different entities included different types of technologies in the DER definition, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system. These DER were counted differently in different entities. Some included only solar PV, some included also energy storage, and some entities included all kind of generation, and also demand response.

Appendix A: Detailed Survey Process with Questions

SPIDERWG determined that the best approach would be to conduct the DER survey in several phases, with the first phase containing general questions regarding DER penetrations and basic modeling practices for each entity. The first phase did not include questions about the DER model parameterization or forecasting, and only included data sources in a cursory manner. SPIDERWG recommends conducting a more detailed follow-up survey of modeling practice upon completion and findings from this phase one survey.[12] The following questions were asked in this phase one survey:

1. What is your company's function(s)?[13]
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What technologies are included in the DER definition used when answering this survey?
5. What is the total capacity of DER connected to your system [MW]?
6. What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?
7. Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped? (can be estimated from change in net load if detailed data is not available)
8. Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?
9. Do you receive any DER operational data (e.g., output of DERs)? On what level?
10. How do you model DERs in load flow studies?
11. What is the MW threshold to explicitly model individual (or multiple) U-DERs in the base case?
12. What is the MW threshold to explicitly model aggregate R-DERs in load flow studies?
13. How are DERs being aggregated in your system?
14. Do you model DERs in dynamic studies?
15. Which DER model do you use in your dynamic studies?
16. Do you model distribution-connected energy storage in your system?
17. How do you model energy storage in your system?

[12] Such questions include DER forecasting methods, sources of DER data, impacts of DERs on base case creation, considerations of DERs in special studies, and study impacts of DERs.
[13] Based on the entity's NERC Registration: https://www.nerc.com/pa/comp/Pages/Registration.aspx.

Appendix B: DER Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values in the charts that follow show the number of respondents and the percentage of total respondents, respectively, for each question.

Question 1

"What is your company function?"[14]

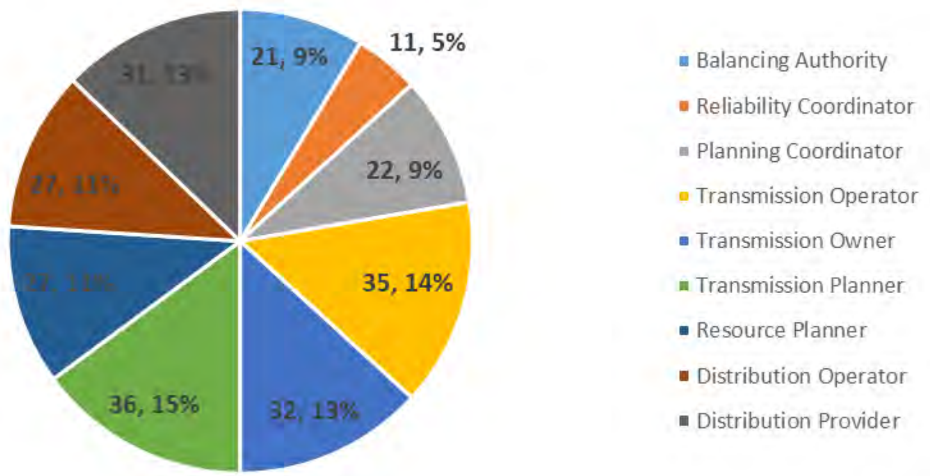


Figure B.1: Responses to Question 1

Key Takeaway – Question 1: A wide array of SPIDERWG members responded to this survey, 36 and 22 entities identifying as TPs and PCs, respectively (not mutually exclusive).

[14] Respondents were requested to mark all that apply; hence the higher response count. 45 entities responded to the survey.

Question 2

"What is the peak gross load of your area [MW]?"

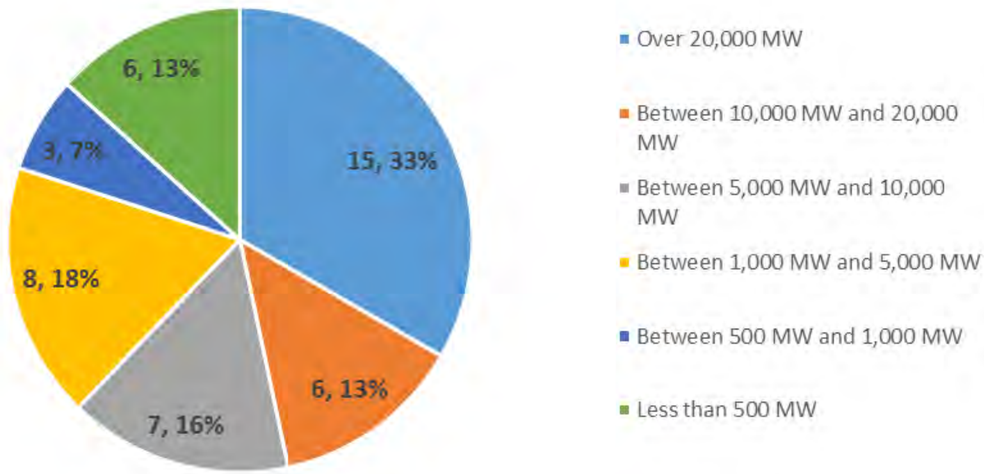


Figure B.2: Responses to Question 2.

Key Takeaway – Question 2:
Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW.

Question 3

"What is the minimum gross load of your area [MW]?"

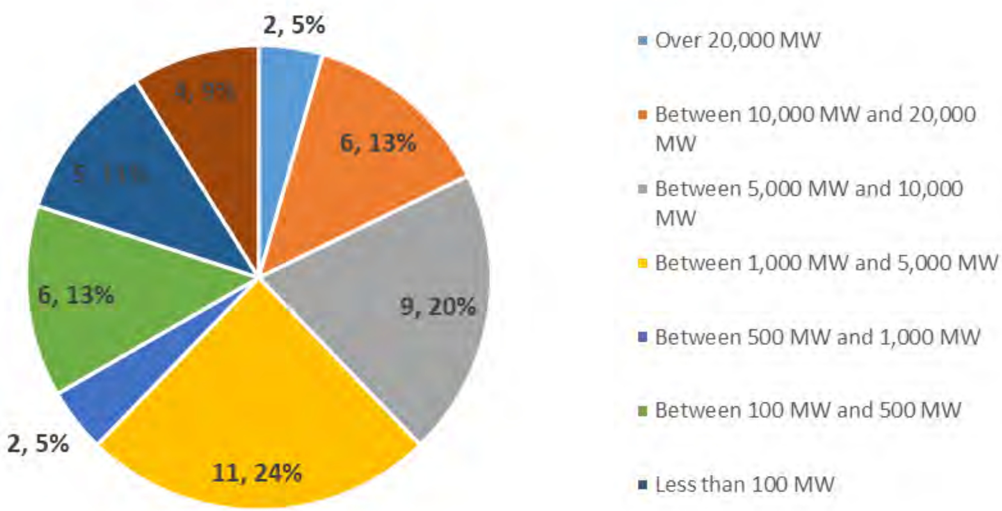


Figure B.3: Responses to Question 3

Key Takeaway – Question 3:
Entities also ranged in their minimum gross load. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.

Question 4

"What technologies are included in the DER definition used when answering this survey?"

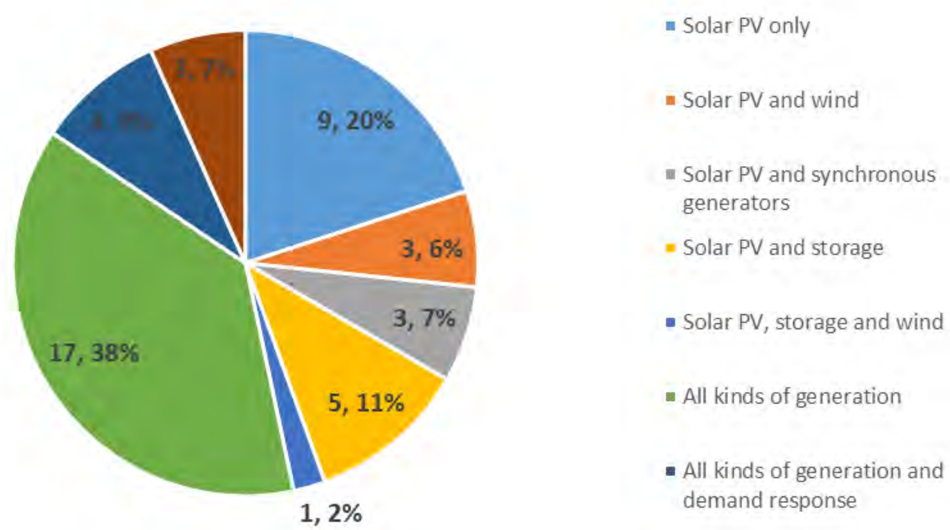


Figure B.4: Responses to Question 4

Key Takeaway – Question 4:
Some entities included demand response in their definition of DER; however, the majority of respondents focused on "sources of electric power" with most focusing specifically on inverter-based DERs such as solar PV, wind, and battery energy storage.

Question 5

"What is the total capacity of DER connected to your system [MW]?" [15]

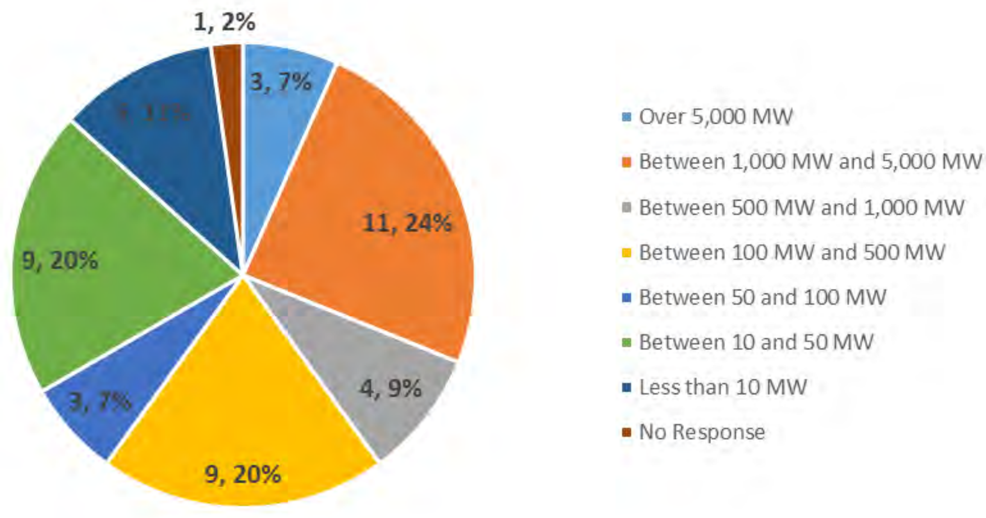


Figure B.5: Responses to Question 5

Key Takeaway – Question 5:
Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.

[15] Regarding this question, since different entities include different types of technologies in the DER definition, as seen from the responses to the previous question, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system based on the SPIDERWG definition.

Question 6

"What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?"[16]

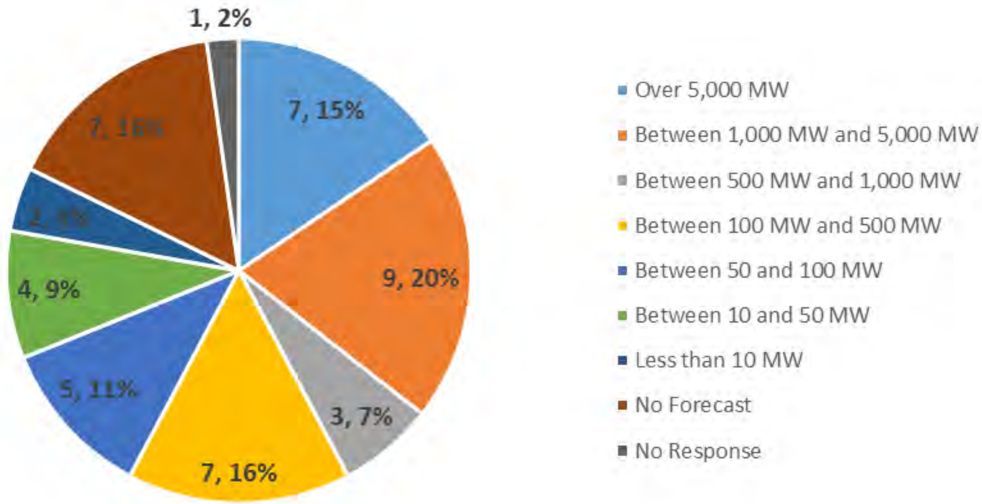


Figure B.6: Responses to Question 6

Key Takeaway – Question 6:
In 2024, over 35% of respondents reported having over 1,000 MW of installed DER in their footprint, about 60% reported having more than 100 MW, and about 24% reported having less than 100 MW. About 15% of respondents reported having no DER forecast out to 2024.

[16] In summarizing the responses to this question, the DER forecast was compared with the existing amount of DER.

Question 7

"Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped?"[17]

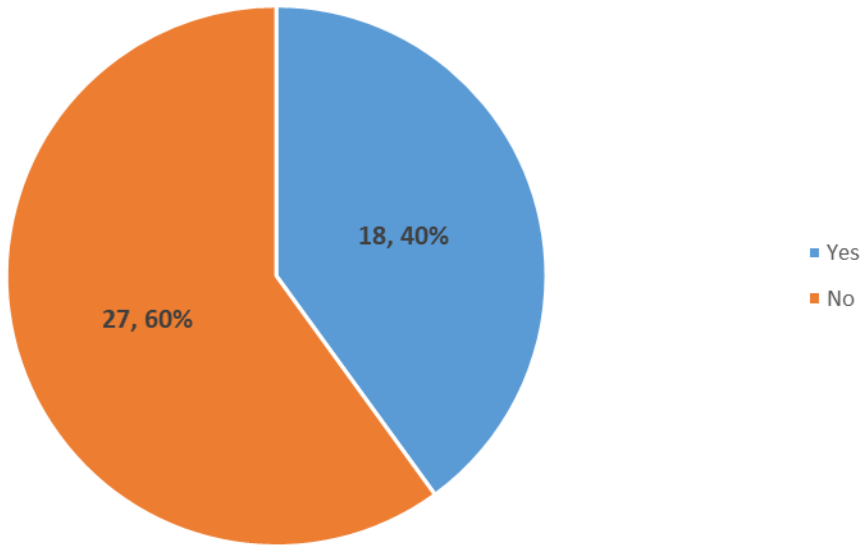


Figure B.7: Responses to Question 7

Key Takeaway – Question 7:
40% of respondents reported observing widespread tripping of DERs during fault events in their footprint; the remaining 60% had not observed any DER-related tripping events so far.

[17] Note that the response to this question can be estimated from the change in net load if detailed data is not available.

Question 8

"Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?"

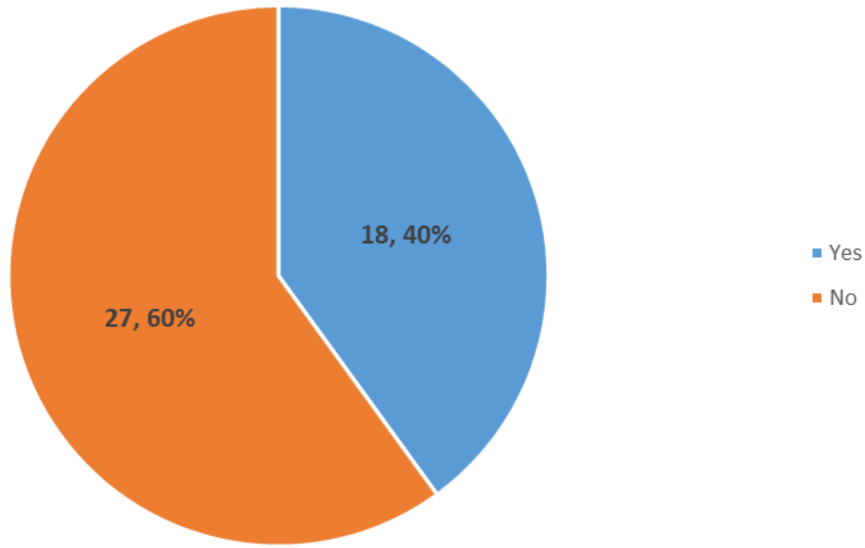


Figure B.8: Responses to Question 8

Key Takeaway – Question 8:
40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon; the remaining 60% had not observed any shift in net loading on their system.

Question 9

"Do you receive any DER operational data (e.g., output of DERs)?"

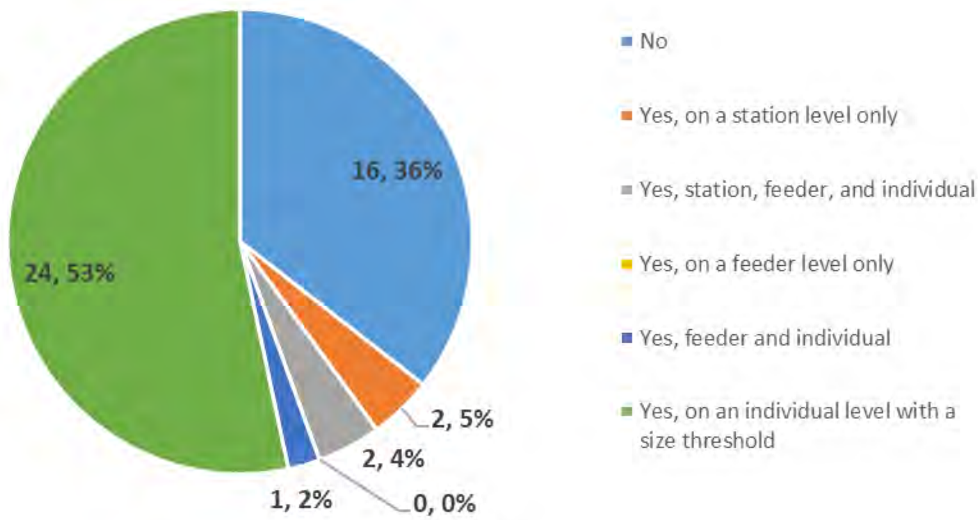


Figure B.9: Responses to Question 9

Key Takeaway – Question 9:
About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner. Some respondents receive limited DER information on a station- or feeder-level.

Question 10

"How do you model DERs in load flow studies?"[18]

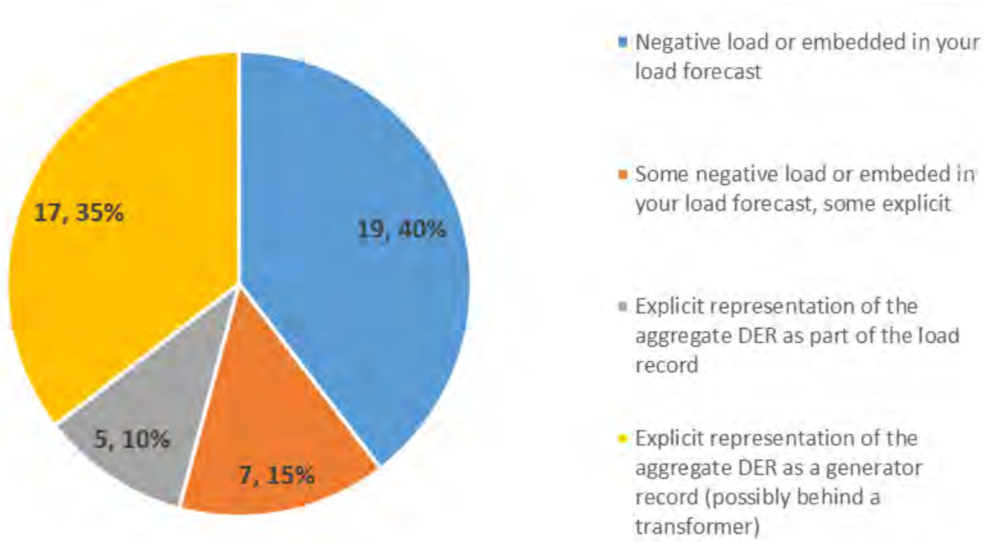


Figure B.10: Responses to Question 10

Key Takeaway – Question 9:
45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no DER representation in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.

[18] Note that the response to this question include some overlap as respondents reported more than one option.

Question 11

"What is the MW threshold to explicitly model individual (or multiple) utility-scale (U-DERs) in the base case?" [19]

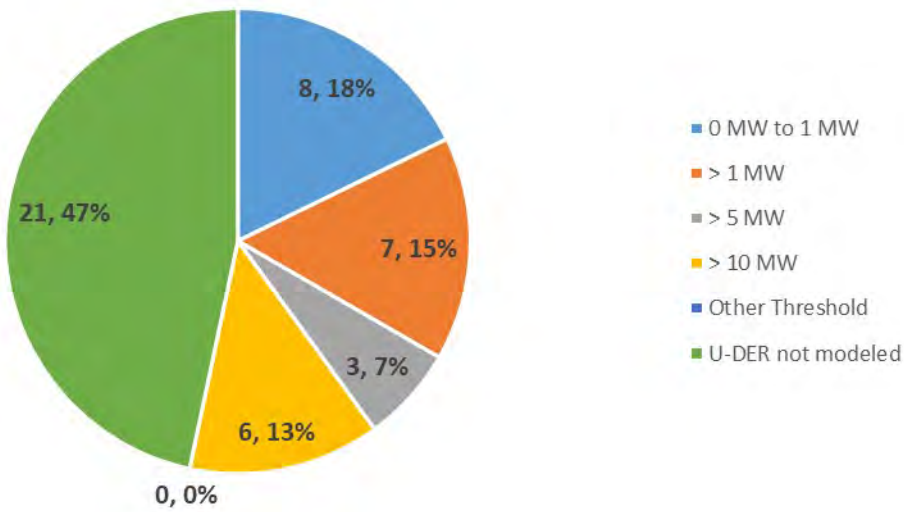


Figure B.11: Responses to Question 11

Key Takeaway – Question 11:
About 50% of respondents do not have a threshold for modeling utility-scale DERs (i.e., larger DERs that are often three-phase installations), and do not model U-DERs in their studies. 13% use a threshold over 10 MW, 7% use a threshold between 5 MW and 10 MW, 15% use a threshold between 1 MW and 5 MW, and 18% use a threshold less than 1 MW.

Question 12

"What is the MW threshold to explicitly model aggregate retail-scale (R-DERs) in load flow studies?"

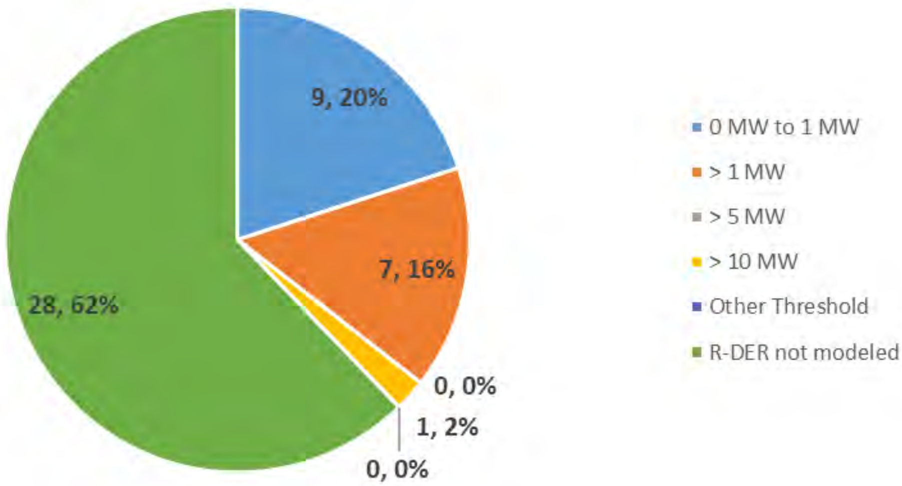


Figure B.12: Responses to Question 12

Key Takeaway – Question 12:
62% of respondents stated that they do not model R-DER to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.

Question 13

"How are DERs being aggregated in your system?"

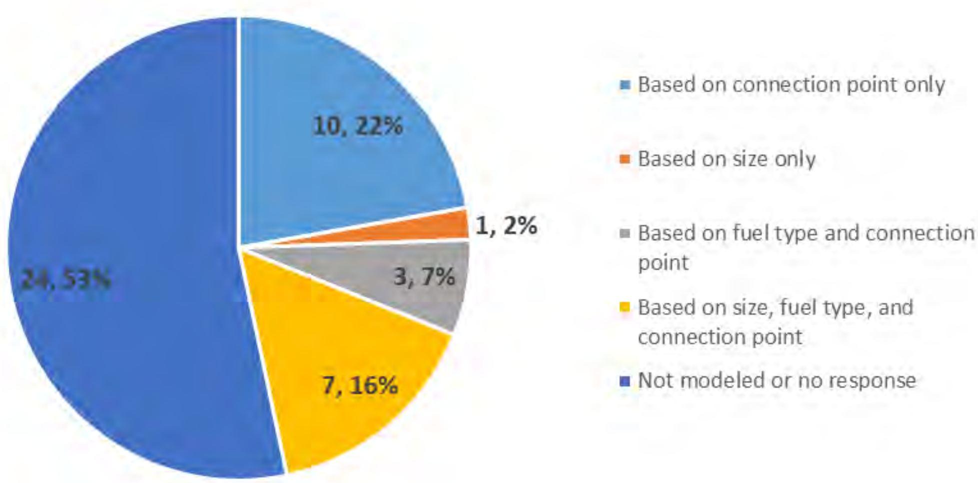


Figure B.13: Responses to Question 13

Key Takeaway – Question 13:
Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.

Question 14

"Do you model DERs in dynamic studies?"

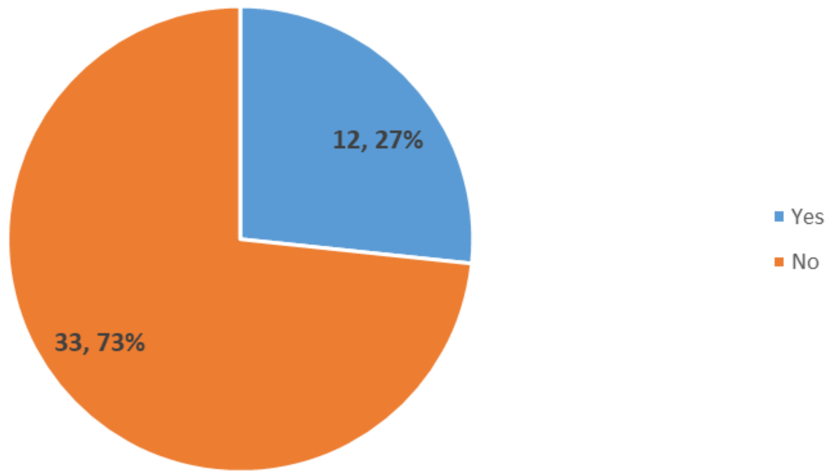


Figure B.14: Responses to Question 14

Key Takeaway – Question 14:
73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.

Question 15

"Which DER model do you use in your dynamic studies?"

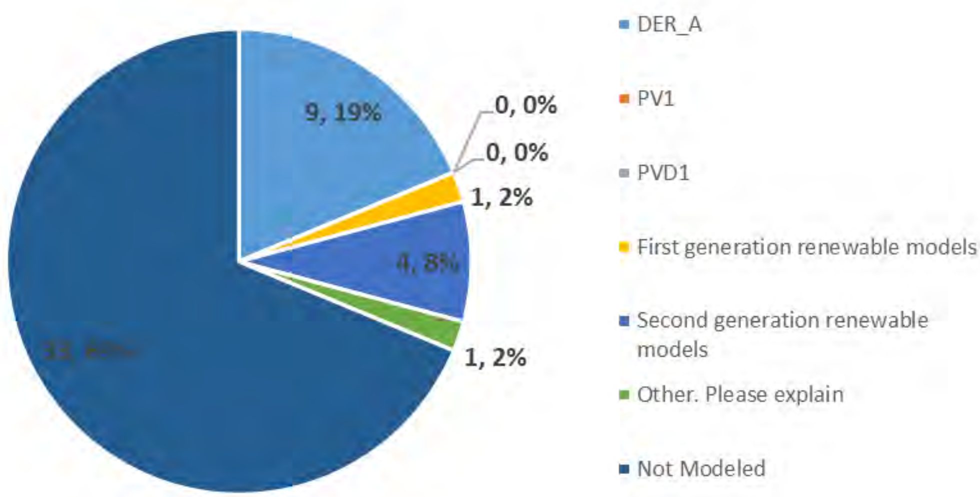


Figure B.15: Responses to Question 15

Key Takeaway – Question 15:
Most respondents reported not modeling DERs in dynamic studies. Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.

Question 16

"Do you model distribution-connected energy storage in your system?"

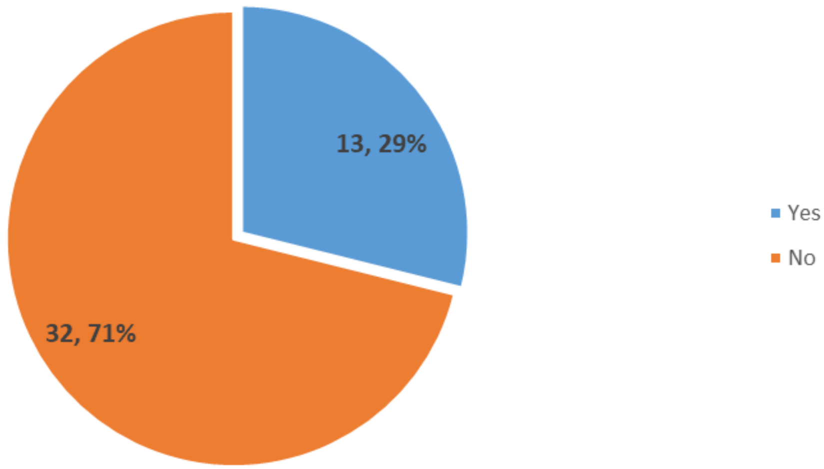


Figure B.16: Responses to Question 16

Key Takeaway – Question 16:
About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage.

Question 17

"How do you model energy storage in your system?"

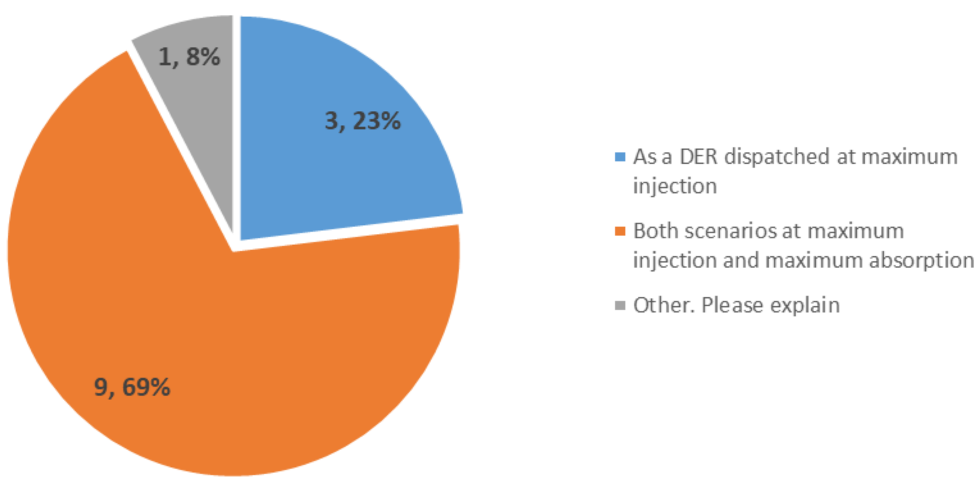


Figure B.17: Responses to Question 17

Key Takeaway – Question 17:
About 70% of respondents stated that they model both scenarios for full injection and full absorption for the distributed battery output; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

Energy Reliability Assessments Task Force (ERATF) Update

Action
Information

Summary
The ERATF will assess risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The ERATF serves the Reliability and Security Technical Committee (RSTC) in providing a formal process to analyze and collaborate with stakeholders to address the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources whitepaper. This whitepaper identified energy availability concerns related to operations/ operations planning and mid- to long-term planning horizons.

Agenda Item 7
Reliability and Security
Technical Committee Meeting
June 9, 2021

Standing Committee Coordination Group (SCCG) Update

Action
Information

Summary
Per the SCCG scope document, the SCCG is to *"provide quarterly reports to the standing committees for inclusion in their public Agenda posting on cross-cutting initiatives addressing risks to the reliability, security, and resilience of the BPS. This report shall be prepared in advance and voted on by the SCCG at the SCCG's quarterly meetings."*

Risk Registry

Action
Information

Summary
In an effort to continually monitor the existing risks to the bulk power system (BPS) and manage the efforts of the ERO Enterprise to actively identify and address new threats, NERC will work with the Standing Committee Coordination Group (SCCG) to create a Risk Registry. This registry will overlap some with the risk profiles identified in the latest ERO Reliability Risk Priorities Report (RISC Report), but the Risk Registry will focus on reporting current risks while the RISC Report is a forward-looking view of the BPS. In an effort to ensure the risk registry captures the right categories of current risks, NERC is seeking feedback on the registry as it is developed.

NERC Bylaws Changes

Action
Information

Summary
On April 5, 2021, FERC approved a series of Bylaws revisions that were approved by the Board in August 2020. Among other changes, the revised Bylaws modified the Sector membership definitions to ensure consistency with the intent of fair and balanced participation in NERC governance by stakeholders with a significant role in the reliability and security of the bulk power system.

North American Generator Forum
RSTC Update

Allen D. Schriver, P.E.
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NextEra Energy
and
COO North American Generator Forum
Allen.Schriver@nexteraenergy.com
June 8, 2021

NAGF Mission

The NAGF mission is to promote the safe, reliable operation of the generator segment of the bulk electric system through generator owner and operator collaboration with grid operators and regulators.

Agenda

- NERC Standard Projects
- Resilience
- NAGF 2021 Annual Meeting

➢ NERC Standard Projects

➢ NERC Standards Projects

- The NAGF is actively engaged in the following NERC Projects to help ensure the generator sector perspective is heard and understood:
  - NERC Project 2017-01: Modifications to BAL-003
  - NERC Project 2019-04: Modifications to PRC-005-6
  - NERC Project 2019-06: Cold Weather
  - NERC Project 2021-01: Modifications to MOD-025 and PRC-019
  - NERC Project 2021-02: Modifications to VAR-002

➢ NAGF Physical Security Working Group

- Focused on the sharing of generator physical security issues as well as promoting physical security practices, threat mitigation strategies, incident prevention/response, training, and other relevant topics to enhance generator physical security and reliability.

Resilience

- NAGF will be presenting at the RF Operational Resilience Webinar on June 8th

- NAGF continuing to:
  - Collaborate with the NATF on opportunities to enhance resilience based on information from the southwest cold weather event of 2021
  - Develop the Generator Resilience Maturity Model

NAGF 2021 Annual Meeting

- NAGF Annual Meeting
  - The NAGF 2021 Annual Meeting WebEx is scheduled for October 12th, 13th and 14th
  - If the RSTC would like the opportunity to present or have a discussion with the NAGF please contact Al Schriver or Wayne Sipperly (wsipperly@generatorforum.org)
- IRPWG
  - Webinar on BESS and Hybrid Systems currently scheduled for Thursday July 15th from 1-3 PM

Q & A

NAGF

the power to make a difference

Thank you!

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North American Transmission
FORUM

Community *Confidentiality* *Candor* *Commitment*

To:	NERC Reliability and Security Technical Committee (RSTC)
From:	Roman Carter (Director-Peer Reviews, Assistance, Training and Knowledge Management)
Date:	May 15th, 2021
Subject:	NATF Periodic Report to the NERC RSTC – June, 2021
Attachments:	NATF External Newsletter (April 2021)

The NATF interfaces with the industry as well as regulatory agencies on key reliability, resiliency, security, and safety topics to promote collaboration, alignment, and continuous improvement, while reducing duplication of effort. Some examples are highlighted below and in the attached April NATF external newsletter, which is also available on our public website: www.natf.net/news/newsletters

NATF-NERC Leadership Meetings

NATF and NERC leadership meet periodically to discuss collaborative work and industry topics. The most-recent call, on March 29, included discussions on important industry topics like facility ratings, vegetation management practices, security, resource adequacy, and pandemic response.

COVID-19 Response

The NATF continues to work with members and industry partners, including NERC, regarding the COVID-19 pandemic. As noted in the newsletter, the NATF and NERC hosted a well-attended webinar on pandemic planning and response activities including a discussion on resources available to industry. Notable presenters included NERC, E-ISAC, EPRI, European Network of Transmission System Operators for Electricity (ENTSO-E) and European Commission (Directorate-General for Energy).

NATF Hosting Virtual Seminars for Members

The health and safety of our staff and members remains our top priority. We continue to partner with members to host virtual activities including workshops. The seminars will allow us to continue adding value to the membership and enable some of the key information-sharing and networking aspects of our typically in-person workshops.

Facility Ratings Practices Implementation

The NATF continues to work with its members to socialize and review member implementation of facility ratings practices developed by a team of subject-matter experts from NATF member companies. The NATF provided an initial summary report on overall member implementation status to NERC and regional entity leadership in early March and will provide updates approximately every six months, with the next report expected towards the end of the third quarter of 2021.

NATF Supply Chain Work

As noted in the attached newsletter, the NATF and the Industry Organizations Team are working through the annual review process of the NATF Criteria and Questionnaire. The revisions were posted for industry-wide comment through April 2. Final changes will be provided to the NATF board for approval in June; upon approval, the revised Questionnaire and Criteria will be posted on the NATF public website.

Redacted Operating Experience Reports

Since our last newsletter, we have posted five reports to the "Documents" section of our public site for members and other utilities to use internally and share with their contractors to help improve safety, reliability, and resiliency.

North American Transmission Forum External Newsletter

April 2021

NATF and NERC Host Webinar on Pandemic Planning and Response Activities

On March 17, the NATF and the North American Electric Reliability Corporation (NERC) hosted a webinar on pandemic planning and response activities as well as resources available to industry. Opening remarks were provided by Commissioner Neil Chatterjee, Federal Energy Regulatory Commission; Tom Galloway, president and CEO of the NATF; and Manny Cancel, senior vice president of NERC and CEO of the Electricity Information Sharing and Analysis Center (E-ISAC). The webinar featured presentations on pandemic activities of the following organizations:

- NATF
- NERC
- E-ISAC
- Electricity Subsector Coordinating Council (ESCC)
- Electric Power Research Institute (EPRI)
- European Network of Transmission System Operators for Electricity (ENTSO-E)
- European Commission (Directorate-General for Energy)

Presentations are posted on the NATF website: https://www.natf.net/industry-initiatives/covid-19.

***

NATF Hosting Virtual Seminars for Members

The health and safety of our staff and members remains our top priority. We continue to work with members and monitor updates from the Centers for Disease Control and Prevention (CDC) and state and local authorities to help inform our decisions about when to return to in-person activities.

The NATF has conducted virtual activities since its inception, and our membership is adept at exchanging information and sharing lessons learned in this format. Since the start of the pandemic, we have continued our standard virtual activities and converted some in-person meetings to webinars. We have also been hosting special webinars on specific topics, including emerging industry issues and pandemic response. We are now adding virtual seminars, which will serve as alternatives for some of our annual in-person workshops. The seminars will allow us to continue adding value to the membership and enable some of the key information-sharing and networking aspects of our workshops.

***

Facility Ratings Practices Implementation

The NATF continues to work with its members to socialize and review member implementation of facility ratings practices developed by a team of subject-matter experts from NATF member companies. The "NATF Facility Ratings Practices Document"—published for members in mid-2020—provides guidance for establishing

sustainable programs, processes, and internal controls to help ensure that facility ratings are accurate and that ratings for equipment and facilities are documented and communicated. The NATF facility ratings practices are consistent with and align with practices and controls suggested by the ERO Enterprise in its November 2019 facility ratings problem statement and in reports and webinars conducted by NERC and the regional entities.

The NATF provided an initial summary report on overall member implementation status to NERC and regional entity leadership in early March and will provide updates approximately every six months, with the next report expected towards the end of the third quarter of 2021.

In addition, NATF staff participates in the joint Compliance and Certification Committee and Reliability and Security Technical Committee Facility Ratings Task Force (FRTF) to help ensure the NATF and FRTF efforts are complementary and not duplicative as the FRTF works to assess the potential reliability risk of facility ratings discrepancies.

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NATF Continues Work on Supply Chain Risk Management

The NATF continues work for the adoption of the "Supplier Cyber Security Assessment Model," which provides a strong foundation to address supply chain risks through a five-step process. Current highlights are noted below.

Continued Refinement of the NATF Questionnaire and Criteria—Comments on Revisions. The NATF has conducted the annual revision process for the NATF "Energy Sector Supply Chain Risk Questionnaire" (Questionnaire) and the "NATF Cyber Security Criteria for Suppliers" (Criteria) to enhance convergence on the information collected from suppliers. The revisions were posted for industry-wide comment through April 2. Final changes will be provided to the NATF board for approval in June; upon approval, the revised Questionnaire and Criteria will be posted on the NATF public website.

Industry Organization Team Goals for 2021. The NATF continues to work externally on supply chain risk management with the Industry Organizations Team consisting of entities, suppliers, third-party assessors, and solution providers. The team has established goals to guide 2021 activities, including the following:

- Adoption of the NATF "Supplier Cyber Security Assessment Model"
- Monitoring of threat and governmental/regulatory landscapes

Learn more about the Industry Organizations Team and projects supporting the 2021 goals at https://www.natf.net/industry-initiatives/supply-chain-industry-coordination.

***

Redacted Operating Experience Reports

Since our last newsletter, we have posted five reports to the "Documents" section of our public site for members and other utilities to use internally and share with their contractors to help improve safety, reliability, and resiliency.

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For more information about the NATF, please visit www.natf.net.