NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Probabilistic Assessment

Technical Guideline Document

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RELIABILITY | ACCOUNTABILITY




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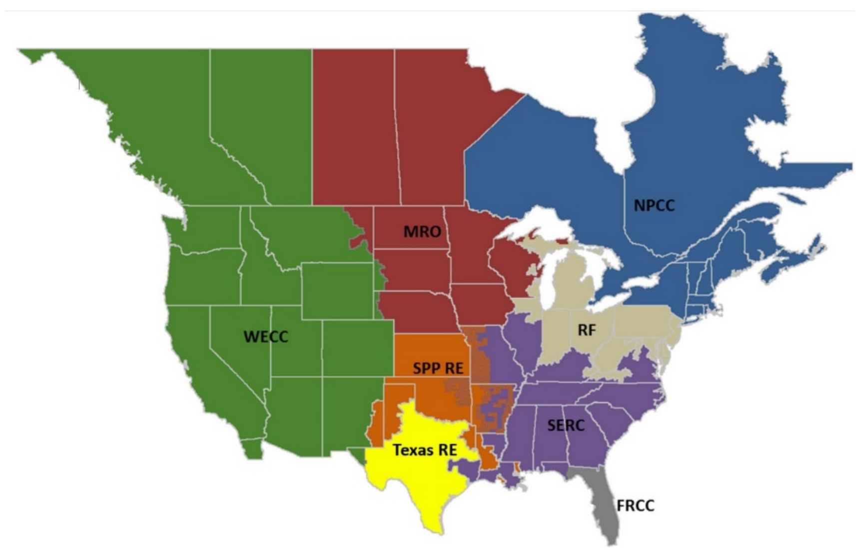
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California in Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

In an effort to improve NERC's continuing probabilistic assessments, the NERC Planning Committee (PC) tasked the Probabilistic Assessment Improvement Task Force (PAITF) with seeking enhancements to the existing Probabilistic Assessment (ProbA). The intent of the ProbA is to probabilistically evaluate resource adequacy based upon current reserve margin projections and emerging risks that have been identified in the Long-Term Reliability Assessment (LTRA).

This Probabilistic Technical Guideline Document serves as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy. It provides guidance for NERC and its Regions and Assessment Areas to improve consistency in conducting probabilistic studies for Assessment Areas, and to establish consistent measures and metrics for monitoring potential resource adequacy trends. In addition, the Probabilistic Assessment Technical Guideline Document outlines suggestions for performing probabilistic analyses and common methods used by different entities while incorporating PAITF's recommendations for enhancing NERC Regions and Assessment Areas' modeling approaches at the time of publication. The Probabilistic Technical Guideline Document may be updated as deemed necessary, per a recommendation by the PC or its subgroups to reflect current modeling practices. The Probabilistic Assessment Technical Guideline Document is not applicable to individual entities or the resource planning activities they conduct for their specific jurisdictional authorities.

Primary Objectives

Under the guidance of the NERC Reliability Assessment Subcommittee (RAS), PAITF has created this Technical Guideline Document to identify and document enhancement opportunities for NERC's Regions and Assessment Areas.

The enhancements put forth by this Probabilistic Technical Guideline Document seek to:

- Identify practices, requirements, and recommendations needed to perform high-quality probabilistic resource adequacy assessments
- Complement reserve margin analyses in NERC's Long-Term Reliability Assessment by producing enhanced resource adequacy metrics and modeling approaches
- Provide NERC and policy makers with greater insight, understanding, and perspective on BPS reliability
- Support regional scenarios to study resource adequacy issues identified in the Long-Term Reliability Assessment

Enhancement Recommendations

The following section highlights major recommendations for enhancement of the ProbA Furthermore, Appendix C of this document provides a full list of recommendations.

- **NERC to develop and maintain documentation describing the establishment of Assessment Areas.** Assessment Areas are established through the NERC Reliability Assessment process. These areas are used for reporting probabilistic metrics. The ERO-RAPA, with input from RAS is to develop and maintain documentation describing the establishment of Assessment Areas. The ERO-RAPA, with input from NERC RAS annually to assess the need to revise the Assessment Areas based on boundary changes as market participation and planning responsibilities change over time. NERC staff, with input from NERC RAS, to provide a supplemental mapping document of changes to Assessment Areas over time.
- **Regions and Assessment Areas need to estimate or calculate monthly resource adequacy metrics.** As resource and demand characteristics change over time, annual loss of load may start accruing during historically off-peak months. Therefore, the monthly aggregation of these metrics [Loss of Load Hours

(LOLH) and Expected Unserved Energy (EUE)] will better inform industry of potential resource adequacy risks throughout the year.

- **Regions and Assessment Areas need to model seasonal load forecast uncertainty.** Current models incorporate some level of load forecast uncertainty, primarily around the annual peak; however, this recommendation seeks incremental improvements in load modeling to capture a reasonable expectation of seasonal load variability around the load forecast. Each Assessment Area is to incorporate both annual and seasonal peak uncertainty influenced by weather, economic, and other drivers in their load modeling.
- **Regions and Assessment Areas need to incorporate seasonal variations in their modeling of resource outages.** Current models incorporate some level of seasonal variation of resource outages through annual average forced outage rates; however, this recommendation seeks incremental improvements in outage modeling to capture a reasonable expectation of seasonal outages for the study years. Each Assessment Area to incorporate seasonal forced outage impacts by utilizing forced-outage rates, deration with load or temperature, varying transition rates, etc. Model modifications may be needed to accommodate this improvement.
- **Assessment Areas need to coordinate with neighboring areas and document coordination and modeling activities.** Each Assessment Area to provide and document further detail probabilistic modeling and coordination efforts with their neighboring entities. This is an incremental improvement to the narratives for increased awareness of Assessment Areas' methods. In addition, Assessment Areas to coordinate and document modeling differences and similarities from the LTRA data in terms of on-peak capacity transfer obligations and seasonal, weekly, or daily variations in the probabilistic model.
- **Assessment Areas to perform the sensitivity modeling within the Core Probabilistic Assessment framework**. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- **Assessment Areas to address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework**. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.

Introduction

Probabilistic analysis describes events in terms of how probable they are, and requires knowledge of the performance characteristics of bulk power system (BPS) components. These performance characteristics may include but not limited to generator outage rates, resource realizations in terms of energy produced, load characteristics, transmission congestions and constrains, etc.,. Measurement of past performance of the BPS can be expressed precisely in terms of frequency, duration, and the number of elements affected in past events. Prediction of future reliability must be expressed in terms of the expected performance of the system components, and of the uncertainty in those expectations. These characteristics can be brought together to derive various measures of the reliability of the BPS. Probabilistic methods typically rely on either statistical analysis of historical performance or enumeration techniques which are capable of simulating large numbers of contingencies. However, the choice of methods and selection of acceptable reliability levels are still matters of judgment and differ from Region to Region (and from utility to utility in some cases).

Probabilistic Modeling Overview

In addition to defining various technical considerations for probabilistic modeling, the PC PAITF Technical Guideline report identifies potential practices, requirements, and recommendations needed to ensure BPS reliability.

The PAITF 2015 ProbA Improvement Plan—Summary and Recommendations report reviewed recent key findings in the 2015 LTRA and ProbA reports resulting in the following conclusions:[1]

- The PAITF to prepare a Probabilistic Assessment Technical Guideline document to address consistency issues by recommending specific modeling guidelines to be used by the individual Assessment Areas.
- NERC and the Regions to take the lead in developing and evaluating additional scenarios to study resource adequacy issues related to resource risk areas identified in LTRAs.
- There are additional reliability issues, not directly related to resource adequacy, to be addressed using different probability analysis techniques. The review of methods and techniques for these non-resource adequacy issues should be identified in a separate report.

The Improvement Plan outlined two approaches that will increase NERC's ability to identify reliability trends as well as assess and evaluate resource adequacy concerns:

- **Core Probabilistic Assessment:** this approach is a continuation of the individual area probability assessments that will be an enhanced version of the current ProbA. Modeling consistency will be improved by following a Probabilistic Assessment Technical Guideline document.
- **NERC-Regional Coordinated Special Assessment:** this approach will expand the probabilistic study efforts through NERC and the Regions taking the lead in developing and evaluating additional scenario studies on resource adequacy concerns related to the BPS identified in LTRAs.

Guidelines for these approaches are demonstrated in this document, and highlight possible enhancements recommended by the PAITF. Each probabilistic enhancement or recommendation in this Technical Guideline Document is tied to one of four improvement areas: 1) process and coordination, 2) data needs and data collection, 3) assumptions criteria and modeling requirements, and 4) modeling software requirements.

[1] NERC Probabilistic Assessment Improvement Plan – Summary and recommendations Report, December 2015, http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ProbA%20%20Summary%20and%20Recommendations%20final%20Dec%2017.pdf

Core Probabilistic Assessment

Metric Reporting Areas

The term “metric reporting area” (MRA) is synonymous with the areas of the BPS which report resource adequacy metrics, such as loss-of-load hours (LOLH). MRAs are meant to be flexible in order to address individual assessment objectives. For the purpose of the Core Probabilistic Assessment, MRAs are synonymous with the reporting Assessment Areas of LTRA.

One key to delivering credible and meaningful Core Probabilistic Assessments is the establishment of Assessment Areas that accurately represent the current and future operations of the system. The intent of establishing these Assessment Areas is to report on the same basis as entities plan and operate their respective system(s).

Assessment Areas are established through the NERC Reliability Assessment processes, and these areas will be used for reporting probabilistic metrics for the Core Probabilistic Assessment under this PAITF recommendation, provided the following:

1. The ERO RAPA, with input from NERC RAS, develops documentation describing the establishment of Assessment Areas.
2. The ERO RAPA, with input from NERC RAS, maintains this documentation and annually assesses the need to revise the Assessment Areas based on boundary changes over time as market participation and planning responsibilities change.
3. NERC staff, with input from NERC RAS, provides a supplemental mapping document of Assessment Areas boundary changes over time.

Metrics Description

Resource adequacy metrics describe the occurrence, frequency, and duration of risk throughout the planning year for an Assessment Area. The LTRA is a peak-driven deterministic approach to gage resource adequacy. However, a compliment to the LTRA’s reported reserve margins is the associated probability of loss of load hours and/or unserved energy at the respective reserve margins. Even if from a deterministic view an hour’s demand is below the expected peak demand, other factors may drive that hour to be more at risk for loss of load than the peak hour due to scheduled and forced outages, transmission constraints, etc. Previous LTRAs have highlighted the need to evaluate more granular metric reporting in order to provide better risk-informed recommendations and leading edge indicators—given an evolving BPS. Probabilistic Assessment indicates trends in risks for any hour of the year, and it provides a trigger for further investigation that may be needed. The monthly aggregation of risk across 8,760 hours of the year may be more suitable to indicate the duration or occurrence of resource adequacy risks in some areas of the BPS.

Historically, the focus of the Core Probabilistic Assessment has been around annual indicators of risk to resource adequacy.

The following and other probabilistic metrics may be produced for different time intervals:

- Loss of Load Probability (LOLP)
- Expected Unserved Energy (EUE)
- Loss of Load Hours (LOLH)
- Loss of Load Expectation (LOLE)
- Loss of Load Event (LOLEV)

Although classic reliability metrics such as LOLE, LOLP and LOLEV have been used for a long time, they are not metrics used in the Core Probabilistic Assessment to avoid potential conflicts with regional practices based on different methods.

Loss-of-Load Probability (LOLP)

This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.

Expected Unserved Energy (EUE)

This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an Assessment Area (i.e., total of peak demand, Net Energy for Load, etc.). Normalizing the EUE provides a measure relative to the size of a given Assessment Area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.

Loss-of-Load Hours (LOLH)

This is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.

Loss-of-Load Expectation (LOLE)

This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original classic metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently some Assessment Areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day.

Loss-of-Load Events (LOLEV)

This is defined as the number of events in which some system load is not served in a given year. A LOLEV can last for one hour or for several continuous hours and can involve the loss of one or several hundred megawatts of load. Note that this is not a probability index, but a frequency of occurrence index.

Metric Calculations

The PAITF recommends calculations of the following metrics for each Assessment Area and study period evaluated for all hours per year:

- Annual LOLH
- Monthly LOLH
- Annual EUE—both actual and normalized

- Monthly EUE—both actual and normalized

Probabilistic Study Reporting

Assessment Areas will perform a probabilistic assessment and report the results to NERC on a biennial basis for study years two and four of the LTRA. The purpose of the duplicate study year from assessment-to-assessment is to track and trend resource adequacy in the near term for each Assessment Area.

Simulation Software

A common software requirement is not necessary. Different models may be used at the discretion of the Assessment Areas. However, these models must be capable of performing the computations required as delineated in the Probabilistic Resource Adequacy Metrics Computations section of this document.

It is recommended that these models utilize a load-generation-transmission simulation software or another type that is appropriate for the Assessment Area for computing the forward-looking probabilistic metrics. The PAITF does not propose a common simulation software requirement in order to allow flexibility at the Assessment Area level. However, the PAITF does recommend that the G&T RPMTF's Assessment Area Simulation Software requirement be adhered to, which states "Each Assessment Area will utilize a load-generation-transmission simulation software for computing forward-looking probabilistic metrics."

It is at the discretion of each Assessment Area to select their solution tool, provided that metrics are calculated through simulation (e.g., Monte Carlo or convolution), while also adhering to all load, generation, and transmission modeling requirements/criteria/guidelines.

Specific Modeling Requirements for Core ProbA

Included Generation Categories

Existing generating resources

Existing generation is all generating resources that are capable of supplying BPS demand. This resource must be in commercial service or be expected to be in commercial service by the end of the current calendar year This includes steam generators, combustion turbine generators, combined cycle generators, wind turbine generators, hydro generators, and generation from various types of energy storage facilities. The characteristics of these resources align with the LTRA Data Form Instructions for existing resources. [2]

Load as a Capacity Resource: Demand that can be curtailed or interrupted under a contractual arrangement can be included as an existing resource from the perspective of capacity modeling. Since these resources are predetermined reductions in demand, they must also satisfy the applicable modeling rules for Demand Side management (DSM).

Future generating resources

For any scenario that includes future time periods, additional capacity is included that meets the requirements as identified in the 2016 LTRA Data Instructions to be a LTRA Tier 1 designated unit.

Excluded Generation Categories

[2] NERC 2016 LTRA Data Form Instructions
http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2016LTRA_Data_Instructions.pdf

Any existing generating resource that supplies non-BPS demand is excluded. Any generating resource that is backup or standby generation that is not obligated to supply BPS demand as instructed by the BPS system operator (direct or indirect instruction) is also excluded.

Scheduled generator retirement: An existing generator with a known retirement date should be removed from the existing resources in applicable study years.

Future generating resources

The Core Probabilistic Assessment determines the amount of additional capacity needed to supply future demand forecasts. Excluded future capacity falls under Tier 2 and Tier 3 generation units' categories identified in the LTRA Data From Instructions.

General Modeling Assumptions

Load Modeling

Load modeling to include the following: 1) Peak load projection and forecast uncertainty, 2) A total of 8,760 hourly annual load profile(s) and their associated probabilistic weightings, 3) Load correlation within each Assessment Area incorporating weather and economic parameters.

In the most generic terms, an hourly (usually an 8,760 hourly annual load shape) load model that includes load forecast uncertainty (LFU) to be used for probabilistic assessments. Fundamentally, the load used in the analysis should describe a reasonable expectation of variability of the load forecast for the study year. It is important to represent the correlation across Assessment Area of load and weather parameters.

LFU models the forecast peak load differently from the actual load to provide uncertainty bands around load shapes. Weather, economic variability and forecast modeling errors are key components in establishing these acceptable bands around the 50/50 load shape projections. Each Assessment Area's narrative should address how the load shape is expected to change prospectively.

The general principles for both single and multi-area analysis are described in NERC's Reliability Assessment Guidebook.[3]

PAITF recommends the following for Assessment Areas with respect to load modeling:

- Each Assessment Area should incorporate both annual peak uncertainty and seasonal variation in their load modeling.
- Each Assessment Area should submit a narrative describing their load modeling assumptions.
- Narratives should also include assumptions made on Demand-Side Management (DSM) modeling within the load shapes and forecasts. The DSM section highlights requirements and DSM modeling improvements.
- Load Forecast Uncertainty (LFU) must be incorporated into the ProbA models at a minimum. The industry standard for LFU modeling is to calculate the probability of load exceeding or falling below the forecast. LFU application can be conducted as a multiplier to the load shape(s), captured in multiple weather years modeling, or a combination thereof.
- This LFU should capture the uncertainty due to weather and economics.
- Weather, economic and forecast trend uncertainty include:
  - Conservation and energy efficiency
  - Historic and future embedded variable generation (wind and solar mainly)
  - Controllable or dispatchable demand response
  - Other load shapes within the Assessment Area (among internal transmission zones)
  - Load shapes of outside areas (external Assessment Areas)
- What is included or excluded from the 50/50 base forecast should be detailed in each Assessment Area's narrative. This narrative should also include the methodology to calculate the 50/50 forecasted load for the study years and how that applies to the load shapes within the model.

[3] NERC Reliability Assessment Guidebook http://www.nerc.com/files/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf

Demand-Side Management

The general issues related to the DSM description, data and modeling are extensively discussed in Chapter 3 of the NERC Reliability Assessment Guideline. In this section of this Technical Guideline Document we will concentrate specifically on the modeling of DSM in probabilistic assessments.

As with any analysis the first concern is to ensure that the DSM is being counted exactly once. If the DSM is modeled as an Emergency Operating Procedure (EOP) or as a dispatchable resource, it must be assured that the load shape and load forecast were constructed to include the demand from the loads that the DSM act on. This often means actively adjusting historic information to add the effect of the DSM back in because historic metered load is often load after the impact of the DSM.

The DSM contains all activities or programs undertaken by an entity to achieve a reduction in Demand. The DSM is often understood to include three components: 1) conservation, 2) energy efficiency (EE), and 3) controllable and dispatchable demand response (DR).[4]

EE resources may be classified into two groups: permanent and user controlled.

Permanent EE is the installations and process improvements that lead to the permanent efficiency of devices, buildings, etc.

User Controlled EE is the implementation of end use customer controlled devices and choices that may shift energy usage at the discretion of the end use customer (i.e., thermostat controls). User controlled EE to be implicitly modeled in the ProbA through load shape(s) and LFU, since one factor in the variability from the 50/50 demand is end-use customer activities. However, permanent EE to be modeled explicitly in the ProbA, at least to the extent that its impacts are known.

The PAITF recommends the following requirements for Assessment Areas with respect to permanent EE modeling:

- Assessment Areas should provide a narrative on their methodology to determine the impact of permanent EE on the historical demand series used for the ProbA model.
- Assessment Area's should provide a narrative on their methodology to determine the impact of permanent EE on the load growth rate(s) used in the ProbA model.
- If an Assessment Area utilizes permanent EE within an organized market, the Assessment Area must ensure that its impact is removed from the historical demand series and also ensure that the future impact on load is explicitly modeled as either a load modifier or as a resource with some defined level of uncertainty applied to its load reduction capability.

DR resources may be classified into two categories: controllable (or dispatchable) and non-controllable (or non-dispatchable).

- Controllable DR is any DSM activities or programs that are directly controlled or dispatched by the System Operator or Load-Serving Entity to influence the amount of electricity used.

- Non-controllable DR is not controlled or dispatched by the System Operator or Load-Serving Entity (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Much like user controlled EE, non-controlled DR should be modeled implicitly in the ProbA through load shape(s) and LFU. However, controllable DR should be modeled both explicitly.

[4] 2016 Long Term Reliability Assessment –Data Form Instructions
http://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/2016LTRA_Data_Instructions.pdf

Only controllable DR shall be modeled explicitly in the ProbA. To further expound upon the definition of controllable DR given above, It is useful to consider three different types of DR differentiated by who controls it—customer, distributor/micro-grid, or grid/market authority/system operator.

- **Customer controlled DR** includes such things as price response (especially to real time rates) and building automation. They are considered to be DSM because they respond to lower demand when price is high which may be triggered by a high expectation or actual loss of load. This DSM is not activated because load is high, but rather is price driven. These tend to be correlated but loss of load does not only occur at high loads especially if it is triggered by generator outages or transmission limitations. The big problem with this type of DSM is lack of available data which lead to incomplete models. This is similar to user controlled EE, and for purposes of the ProbA falls outside the scope of controllable DR.
- **Dispatchable** DSM is fairly simple to directly model either as an EOP or as a grid controlled resource. The data is usually readily available and it is, in practice, directly dispatched as needed by the system operator. It has unique features of weather and time-of-day correlations, often a maximum number of occurrences limit and there may be a maximum period over which it may be used. These may need some special treatment in the modeling but they can usually be approximated by utilizing some of the model features designed for thermal or hydro-electric generation is necessary. For the purposes of the ProbA this type of DSM is considered controllable DR.
- **Distributor/Micro-Grid controlled DSM** falls between customer controlled and grid controlled DSM. It is similar to grid controlled but is dispatched based on local needs and system signals such as price. This hybrid DSM is fairly rare so far and specific system characteristics will dictate whether it should be modeled similarly to grid controlled DSM or customer controlled DSM.

Controllable DR, like any other resource should have its intrinsic uncertainty modeled. It has an uncertain capacity impact similar to the uncertainty introduced by thermal generation forced outages. Controllable DR has a much more muted effect typically however as it acts like an aggregation of a large number of small units. Its expected available capacity would exhibit a low variability. This variability is usually much less than the uncertainty in estimating the overall impact. Modeling controllable DR as a deterministic resource may be quite acceptable.

Whether controllable DR is modeled as an EOP or a dispatchable resource doesn't directly impact a probabilistic resource adequacy assessment. However, controllable DR and its intrinsic uncertainty should be modeled explicitly in the ProbA.

PAITF recommends the following requirements Assessment Areas with respect to controllable DR modeling:

- Assessment Area's must provide a narrative on their modeling methodology.
- Assessment Area's must model the limitations associated with controllable DR through one of the following approaches.
  - Assessment areas must model the limitations based on program performance and/or contractual obligations as a load modifier or energy limited resource.
  - If the probabilistic approach is not available, use a net value of MW reduction impact into the model. Include a detailed narrative of how the net value is calculated.

Capacity Modeling

Accurate capacity modeling is important in order to correctly produce probabilistic analysis. Generation resources can be of many forms including, but not limited to, combustion turbine, steam turbine, and pumped storage, utilizing numerous types of fuels such as nuclear, fossil, solar, wind, and hydro. Some entities also consider certain DSM programs as generation resources.

In probabilistic capacity modeling, if the primary energy supply (energy to be converted to electricity) is limited or cannot be controlled by the generator operator, the probability consideration for that capacity will be consistent with the Variable Energy Resources (VER) capacity modeling guidelines in this section. When the primary energy supply (energy to be converted to electricity) is controllable by the generator operator, the probability consideration for that capacity will be based on the equipment outage performance.

Thermal Generation

Combinations of capacity ratings, outage rates, and other thermal parameters such as duration curves and ramp rates can be used to model the variability of thermal generation resources. Below are minimum requirements and PAITF recommendations for thermal generation modeling.

Ratings

The PAITF recommends for Assessment Areas that:

- Thermal generation resources in each Assessment Area should be modeled capturing seasonal capacity ratings. Since the goal of monthly indices such as the LOLH is to identify whether risks are greater in different times of the year, appropriate modeling of seasonal ratings is essential to evaluate risk throughout the calendar year.
- Assessment Area’s narratives shall include how seasonal ratings are derived.
- Thermal generation capacity ratings should be consistent with the LTRA data collection process as indicated in recent LTRA report instructions.

Outage Rates

Forced Outages: Forced-outage rates (FOR) vary between resource types and areas. Most Assessment Areas are using FOR based on annual or seasonal averages. Generator performance is evaluated over long time periods generally 3–5 years and across various seasons. This allows for creating generator performance averages that may include seasonal variations.

PAITF recommends the following for Assessment Areas:

- Incorporating seasonal forced outage factor by either changing forced-outage rates with load or temperature or by derating generation specifically to account for this effect could improve the realism of the ProbA simulations. Model modifications may be needed to accommodate this improvement.
- Unit deratings should be reflected in the FOR, the unit transition states, and/or energy profiles with respect to unit’s historical performances and unit’s data availability.
- Assessment Area’s narratives should include but not be limited to:
  - How forced outage ratings and derates are derived for each unit or by resource fuel type.
  - Ambient and seasonal conditions impacts such as temperature and heat indices.
  - How maintenance and reserve shut down hours are incorporated.
  - What type of FOR is utilized based on units’ loading characteristics (e.g., EFOR or EFORd).

Scheduled Outages:
Scheduled outages should be considered within the probabilistic model. These outages may be categorized into the following groups: 1) Planned Outages—scheduled well in advance, and 2) Maintenance Outages—delayed maintenance in response to unforeseen events. Two approaches may be employed to account for scheduled outages model—random events or fixed schedules.

PAITF recommends with respect to modeling scheduled outages that each Assessment Area document its approach, either as a random schedule or a fixed schedule approach.

Variable Energy Resources

Wind and Solar Energy Resources

Wind and solar resources which are serving the BPS demand are required to be modeled. For instance, the impact of distributed solar should be reflected in load shapes and load forecast uncertainty models. Currently there is no standard method for modeling Variable Energy Resources (VER) in probabilistic assessment of power systems within the industry; however, a range of approaches have been proposed and implemented in academia and industry, each with their own inherent limitations. Given the intermittent nature of VER, these pose challenges in modeling and reliability analyses. It is recommended that a time series model be used in the probabilistic assessment of VER as time series models provide accurate predictions of the behavior of stochastic processes such as the variations in wind speed or solar radiation. The industry has not, however, been ready for using such time series model in probabilistic assessment of power systems containing VER yet. VER should be modeled as a stochastic parameter in the probabilistic assessment in which a key determinant of reliability is the ability of other resources to support the reliability index during periods of low availability of intermittent resources. This means that there needs to be information regarding the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as distribution of discrete samplings such as a number of years of historical resource availability (e.g., wind production or hydro production and/or reservoir information). As an interim solution, the following approach may be used:

- VER may be modeled assuming a certain probability distribution. The probability distribution function can be developed with reference to actual historical data. The models should be able to capture the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as a distribution of discrete variables such as a number of years of historical resource availability.
- Alternatively, seasonal accredited Capacity Contribution or some time referred to as the Effective Load Carrying Capability (ELCC) for variable resources should be used in the model. At least two values, one for the defined summer period and one for the defined winter period, can be used in the probabilistic assessment.

Each Assessment Area should document how each of these resources are modeled and what data is used. PAITF recommends that each Assessment Area:

- Describe how the ELCC or Capacity Contribution calculation is modeled across the year. If available, monthly or seasonal ELCCs, Capacity Contribution Calculations, or per-unit wind and/or solar generation profiles, based on history, for each significantly different wind or solar patterned zone in each Region/Assessment Area should be modeled.
- Provide the justification and methodology for the determination of the probability distribution function and seasonal accredited values for VER.

- Categorize the existing and annual future installed capacity of all wind resources and solar resources by each significantly different wind or solar patterned zone in your Region/Assessment Area. If available, provide these annual quantities on a monthly or seasonal basis.

Energy limited Resources

Energy limited generation such as hydro generation is an important source for electricity in North America. In some of the jurisdictions (e.g., Manitoba Hydro) energy limited generation comprises up to 90 percent of their total resources.

Typically there are three types of hydro resources including pumped storage, storage capable, and run of river. Currently these resources are primarily modeled either as thermal units or as deterministic load modifiers in probabilistic assessment of power systems in the industry. Modeling energy limited hydro unit as a thermal unit using the average FOR may produce performance results that are too optimistic. Modeling hydro units as simple deterministic load modifiers may not accurately incorporate the uncertainties associated with the primary resource of water; therefore, energy limited resources to be modeled probabilistically to recognize and reflect the variability in the primary source of water.

The PAITF recommends the following for Assessment Areas with respect to energy limited resources' modeling:

- Each Assessment Area should document how each of the energy limited resources are modeled and what data is used:
  - The type of hydro modeling approach currently used.
  - The capacity amount that can be reliably maintained for at least one full hour—designate number of hours if stated capacity amount can be sustained longer than one hour.
  - The annual forced outage rates, based on history, incorporating units impound times.
  - Storage maximum capacity in MWh values incorporating impound and discharging times.
  - The operating procedures for units' charging.
- For probabilistic assessment, water flows developed using historical data. The water flow can be treated as a random variable with a certain distribution and can be treated either as a continuous random variable using probability distribution function (PDF) or as a discrete random variable using probability mass function (PMF). The PDF and the PMF can be developed with reference to the historical water flows.
- Each Assessment Area should document in detail the justifications and methodologies for the development of the PDF/PMF, determination of the probabilities of different water conditions, and the modeling of hydro unit as an equivalent thermal unit
- Once the primary source of energy is modeled, the available capacity and energy can be determined considering the forced unavailability of the generating units and the associated storage capability.
- Alternatively Assessment Areas can model hydro units using the following approximate methods:
  - Deterministic load modifiers considering different water conditions (dry, wet, seasonal) with certain probabilities and calculate the weighted average indices
  - Analytical thermal equivalent approach modifying by either the capacity or the forced outage rate

Behind the Meter Generation

Behind the Meter Generation is a generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail load with electric energy[5]. There is a wide array of methodologies on how the BTMGs are incorporated in each Assessment Area.

PAITF recommends the following for Assessment Areas with regards to the BTMG resources*:*

- Each Assessment Area includes in their narrative if BTMGs are modeled and if so how within their respective areas.
- The narrative needs to detail how each Assessment Area treats the BTMGs, either as a resource or a load modifier, etc. and how they insure that the BTMGs are not double counted.
- For the BTMGs modeled as a resource category, they should follow capacity modeling recommendations.

Capacity Transfers: Imports and Exports

Imports and exports across areas of the BPS are generally categorized as two types: "firm" or "non-firm" transactions. Firm transactions are set in advance with firm scheduled transmission from the seller (source) to the purchaser (sink). Non-firm transactions occur from area-to-area as needed to assist to meet load and reliability obligations and are dependent upon the availability of resources and the transmission system after taking scheduled transactions into account.

Modeling approach for both types of imports and exports to capture: a) the variability in availability of the resources and transmission paths associated with the transactions, and b) the priority of firm transactions over non-firm transactions. However, given the complexity of this modeling approach and software limitations, the following is a list of acceptable modeling approaches from the PAITF for Assessment Areas:

- Firm Imports[6]
  - Net capacity transfers based on historical schedules and/or actual flows
  - Net capacity transfers based on contract amount
  - Internal thermal generation with forced outage rates and a commensurate reduction in the interface limits
- Non-Firm Imports
  - No reliance on non-firm support
  - A function of remaining capacity and interface limits. The interface limits should be adjusted to reflect the firm purchases/sales. Resource allocation should attempt to represent established markets and/or reserve sharing groups as much as possible within the model. See Transmission Modeling section recommendations on establishing interfaces and limitations.
- Firm Exports: Similar to either "Firm Imports" net capacity approaches.
- Non-Firm Exports: Similar to "Non-Firm Imports"

Along with adhering to the recommended approaches to modeling imports and exports, PAITF recommends the following requirements with respect to modeling capacity transactions:

[5] 2015 LTRA Data Instructions

[6] All approaches should consider firm transmission service and deliverability limitations

- Assessment Areas should coordinate with neighboring areas to determine the appropriate amount of import/export contractual obligations for probabilistic modeling and shall provide documentation of this coordination effort (including impact of imports/exports on the neighboring area's reliability).
- Assessment Areas should coordinate with neighboring areas to determine reasonable assumptions regarding external resources and load modeling that impact non-firm support.
- Assessment Areas should document their modeling methodology and assumptions.
- Assessment Areas should understand and document modeling similarities and differences from the LTRA in terms of peak MW amounts and seasonal/weekly/or daily variations of modeled flows in the probabilistic model.

Emergency Operating Procedures (EOP)

Emergency operating procedures (EOP) provide a plan for system operators when responding to capacity and energy emergencies on their respective systems. These procedures generally include alerts, warnings, as well as event levels to mitigate capacity and energy deficiencies in real-time.

EOP resources are the last line of defense prior to loss of firm load. Each assessment area decides whether or not to include the use of EOP in the planning criteria that determines the minimum amount of planning reserves for its area. Including or excluding the use of EOP in the Core Probabilistic Assessment should be consistent with the planning criteria for the assessment area.

When modeling EOP, Assessment Areas should consider the variability in the amount of relief obtainable and how it is prioritized with respect to other resources in the model. The key modeling assumptions of any EOP action are the priority level assigned to the resource whether capacity or load modifying, the variability of the amount of load and capacity relief, and the relationship these actions have with respect to neighboring modeled systems, particularly with respect to emergency capacity imports and exports.

The PAITF recommends the following for Assessment Areas with respect to EOP modeling:

- Assessment Areas should provide a narrative describing their methodology in determining the amount of EOP benefits for each EOP step. Specifically addressing at a minimum the following:
  - The amount counted for voltage reduction, and how the amount obtainable is determined.
  - The amount counted for public notice, and how the amount obtainable is determined.
  - Summarize all other EOP types, the amount of relief, and how the amount obtainable is determined.
- EOP should be modeled adhering to the guidelines in previous sections (i.e., Thermal, Imports, DR, etc.)
- EOP should be last available action modeled to serve load, and each step of the EOP should be explicitly modeled.
- Seasonal variability of EOP should be included when appropriate (e.g., DR, Capacity Resources, etc.)

If it is not modeled, PAITF recommends that each Assessment Area supplies thorough documentation explaining why they have decided not to model EOP, and summarize the impact this decision has on the probabilistic assessment results.

Transmission Modeling

Internal and external Transmission modeling and deliverability assumptions are key components in producing probabilistic analysis. Often, transmission is modeled deterministically into the probabilistic model, but it can be modeled probabilistically. Flexibility should be maintained to allow Assessment Areas to define their modeling and deliverability requirements.

Transmission systems are typically modeled on a nodal (power flow) or zonal (pipe and bubble) basis. The determination on which method used is dependent on model simulation software capabilities and system characteristics. The amount of transmission zones and interface limits are dependent on the Assessment Areas' topology.

With respect to transmission modeling, PAITF recommends for Assessment Areas the following:

- Internal and external modeling constraints need to be addressed.
- Flexibility should be maintained to allow Assessment Areas to define their modeling and deliverability requirements.
- Each Assessment Area i*include*s in their narrative how transmission is *modeled within their respective areas*
- Specify how the transmission limits are determined and the approach(s) being used.
- Document transmission additions and retirements for years two and four that are included in the modeling: explain any differences between the modeled transmission additions and retirements, and explain the differences between the transmission addition and retirement data provided for the LTRA.
- Describe the Assessment Areas' transmission modeling approach: how that approach takes into account transmission constraints and outages within and outside of the Assessment Area, and how it developed the data needed for modeling that is consistent with its planning processes. If transmission constraints (e.g., thermal, voltage, stability, or interface limits) are used in the Assessment Areas' process, the methodology should be described. The Assessment Areas should also describe how deliverability of internal and external resources as well as access to external supplemental resources are addressed.

Sensitivity and Scenario Modeling

Sensitivity Modeling: Sensitivity analyses are run to assess the impact of a change in an input (either load, transmission or resource-related) on resource adequacy metrics. The runs are performed by changing one input at-a-time in order to isolate the potential impact of each input. Ideally, the change in each input should be accompanied by an associated probability.

Scenario Modeling: In its most general form, a scenario analysis is performed to assess the impact of changes in multiples inputs (either load, transmission or resource-related) on resource adequacy metrics. The runs are performed by changing multiple inputs at the same time. Ideally, each scenario should have an associated probability calculated based on the changes in inputs included within the scenario. Scenarios are likely to be identified in the LTRA or by sensitivity analysis results. In some cases, scenario analysis may require additional inputs (not included in the Core Probabilistic Assessment) relevant to address a specific reliability concern.

PAITF recommends the following for Assessment Areas:

- The sensitivity modeling should be addressed within the Core Probabilistic Assessment framework. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- The scenario modeling should address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.

Coordinated NERC Regional Special Assessments

This approach is a coordinated effort between NERC and the Regions to utilize a common assessment method to evaluate and report on various resource adequacy issues. The purpose of this approach is to address potential resource adequacy concerns. The approach will identify uncertainties and trends using a uniform NERC probabilistic analysis. NERC will work closely with the Regions and Assessment Areas to conduct complimentary analyses to assess potential risks to reliability.

Special Assessment Determination

Driving factors are key findings from NERC's LTRA and core probabilistic assessments. If there is no existing study effort or market rules to address the issues, NERC (with inputs from RAS, PC, and ERO-RAPA as well as the Assessment Areas) will develop the risk analysis framework to identify the need to perform this assessment. NERC, the Regions, and representatives from each Assessment Area will work closely together to sufficiently conduct the analysis.

Roles and Responsibilities

A Coordinated NERC-Regional Special Assessment encompasses the deployment of a coordinated effort between NERC and the Regions to evaluate, assess, and report developing reliability concerns on Assessment Area resource adequacy using a common assessment method as shown below:

- **Coordination**: NERC will work closely with the Region(s) and Assessment Areas to develop a complementary study scope. Study results developed throughout the study will be shared with NERC and the Regions.
- **Data Collection**: The Region(s) will be responsible for collecting the required data to run the probabilistic study.
- **Modeling**: NERC has in-house probabilistic modeling capabilities to run a special assessment and responsibilities of running the model will be determined through a scope of work document.
- **Reviewing**: Overall peer review process is determined in the scope of work through NERC RAS. Inputs and feedback from the PC and ERO-RAPA are key elements in the development. Endorsements and approval process are topic dependent.

Modeling Requirements and Scope of Work

The special assessment should follow the general methods and assumptions of this Technical Guideline Document; however, deviations from general methods and assumptions may be required to support the scope of the special assessment work. This special assessment occurs at the request of NERC's PC and ERO-RAPA focusing on specific systems and areas of concern. Detailed milestones are left for NERC and Region(s) to assign.

Appendix A: Definitions

Backup/standby generators: These are customer owned generators that may be used to supply emergency power or other short term power needs. If this generation is obligated to operate at the instruction of a system operator, and will supply BPS demand, it can be included as a capacity resource. If operation is at the discretion of the backup/standby generator owner, this generator must be excluded.

BPS demand: This is the aggregated customer demand that the BPS is responsible for supplying from the BPS facilities.

Capable of supplying: These are resources that are connected to the BPS or are resources that reduce the BPS demand when generating.

Directly or indirectly supplied BPS demand: Direct supply is generation controlled by a BPS operator. Indirect supply is BTM generation that reduces BPS demand.

Direct or indirect instruction: Dispatch instructions provided to the generator operator via phone call or EMS signal (direct) or instructions provided to a third party that contacts the operator (indirect).

Future generating resource: A generator facility, planned or under construction, but not expected to be in commercial service by the end of the current calendar year.

Non-BPS demand: This is demand that is not included in any aggregation of BPS demand. This is customer demand supplied solely by customer owned generation.

NSC—Net seasonal capability: The maximum MW output of the generator given the expected ambient conditions of the season.

Primary energy supply: The energy (coal, wind, sunlight, water in a reservoir, etc.) delivered to the generating resource that is converted to electricity.

Appendix B: Contacts

The North American Electric Reliability Corporation

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Atlanta, GA 30326
404-446-2560

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Washington, DC 20005
202-400-3000

NERC Staff

Name	Position
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John N. Moura	Director, Reliability Assessment and System Analysis
Thomas Coleman	Director, Reliability Assessment
Noha Abdel-Karim	Senior Engineer, Reliability Assessment
David Calderon	Engineer, Reliability Assessment
Elliott Nethercutt	Senior Technical Advisor, Reliability Assessment
Michelle Marx	Executive Assistant, Reliability Assessment and System Analysis

NERC Probabilistic Assessment Improvement Task Force Roster[7]

Name	Region/Organization
Josh Collins (Chairman)	SERC
Layne Brown	WECC
Matthew Elkins	WECC
Vince Ordax	FRCC
Richard Becker	FRCC
Philip A. Fedora	NPCC
Ryan Westphal	MISO
Jordan Cole	MISO
Chris Haley	SPP
Alex Crawford	SPP
Paul Kure	RF
Patricio Garrido	PJM
Lewis De La Rosa	TEXAS-RE
Brad Wood	TEXAS-RE
Kevan Jefferies	Ontario Power Generation
David Jacobson	Manitoba Hydro
Bagen Bagen	Manitoba Hydro
Dange Huang	Manitoba Hydro
Joel Dison	Southern Company
Dale Burmester	American Transmission Company
Russell Schussler	Georgia Transmission Corporation
Anish Gaikwad	Electric Power Research Institute
Mark Walling	GE Energy Management
Chi Hung Kelvin Chu	GE Energy Management
Salva Andiappan (Observer)	MRO
Alan Phung (Observer)	FERC
Richard Sobonya (Observer)	FERC

[7] Probabilistic Assessment Improvement Task Force (PAITF) is a task force from the PC members, members from the RAS and selected observers from the industry. PAITF was formed in May 2015, following the March 2015 release of the 2014 Probabilistic Assessment report with a main mission to identify improvement opportunities by developing an improvement plan and a Probabilistic Technical Guideline Document with recommendations to enhance NERC's future probabilistic assessments.

Appendix C: Full List of Recommendations

- NERC to develop and maintain documentation describing the establishment of Assessment Areas.
- Core ProbA to remain biennial work product.
- It is at the discretion of each Assessment Area to select their solution tool, provided that metrics are calculated through simulation (e.g., Monte Carlo or convolution), while also adhering to all load, generation, and transmission modeling requirements/criteria/guidelines.
- In general resources modeled in Core ProbA to align with the LTRA Data Form Instructions with some exclusions of future generating resources based on confidence factor of resource being built.

Load Modeling

- **Each Assessment Area should incorporate both annual peak uncertainty and seasonal variation** in their load modeling.
- Each Assessment Area should submit a narrative describing their load modeling assumptions.
- Narratives should also include assumptions made on Demand-Side Management (DSM) modeling within the load shapes and forecasts. The DSM section highlights requirements and DSM modeling improvements.
- Load Forecast Uncertainty (LFU) must be incorporated into the ProbA models at a minimum. The industry standard for LFU modeling is to calculate the probability of load exceeding or falling below the forecast. LFU application can be conducted as a multiplier to the load shape(s), captured in multiple weather years modeling, or a combination thereof.
    - This LFU should capture the uncertainty due to weather and economics.
- Weather, economic and forecast trend uncertainty include:
    - Conservation and energy efficiency
    - Historic and future embedded variable generation (wind and solar mainly)
    - Controllable or dispatchable demand response
    - Other load shapes within the Assessment Area (among internal transmission zones)
    - Load shapes of outside areas (external Assessment Areas)
- What is included or excluded from the 50/50 base forecast should be detailed in each Assessment Area's narrative. This narrative should also include the methodology to calculate the 50/50 forecasted load for the study years and how that applies to the load shapes within the model.

Permanent Energy Efficiency Modeling (DSM)

- Assessment Areas should provide a narrative on their methodology to determine the impact of permanent EE on the historical demand series used for the ProbA model.
- Assessment Area's should provide a narrative on their methodology to determine the impact of permanent EE on the load growth rate(s) used in the ProbA model.
- If an Assessment Area utilizes permanent EE within an organized market, the Assessment Area must ensure that its impact is removed from the historical demand series and also ensure that the future impact on load is explicitly modeled as either a load modifier or as a resource with some defined level of uncertainty applied to its load reduction capability.

Controllable Demand Response Modeling (DSM)

- Assessment Area's must provide a narrative on their modeling methodology.
- Assessment Area's must model the limitations associated with controllable DR through one of the following approaches.
- Assessment areas must model the limitations based on program performance and/or contractual obligations as a load modifier or energy limited resource.
- If the probabilistic approach is not available, use a net value of MW reduction impact into the model. Include a detailed narrative of how the net value is calculated

Capacity Ratings

- Thermal generation resources in each Assessment Area should be modeled capturing seasonal capacity ratings. Since the goal of monthly indices such as the LOLH is to identify whether risks are greater in different times of the year, appropriate modeling of seasonal ratings is essential to evaluate risk throughout the calendar year.
- Assessment Area's narratives shall include how seasonal ratings are derived.
- Thermal generation capacity ratings should be consistent with the LTRA data collection process as indicated in recent LTRA report instructions.

Forced Outages

- Incorporating seasonal forced outage factor by either changing forced-outage rates with load or temperature or by derating generation specifically to account for this effect could improve the realism of the ProbA simulations. Model modifications may be needed to accommodate this improvement.
- Unit deratings should be reflected in the FOR, the unit transition states, and/or energy profiles with respect to unit's historical performances and unit's data availability.
- Assessment Area's narratives should include but not be limited to:
  - How forced outage ratings and derates are derived for each unit or by resource fuel type.
  - Ambient and seasonal conditions impacts such as temperature and heat indices.
  - How maintenance and reserve shut down hours are incorporated.
  - What type of FOR is utilized based on units' loading characteristics (e.g., EFOR or EFORd).

Scheduled Outages

- PAITF recommends with respect to modeling scheduled outages that each Assessment Area document its approach, either as a random schedule or a fixed schedule approach.

Variable Energy Resource (VER) Modeling

- VER may be modeled assuming a certain probability distribution. The probability distribution function can be developed with reference to actual historical data. The models should be able to capture the uncertainty distribution of the parameter, expressed either as mean and standard deviation in the case of a normal distribution, a more sophisticated non-normal statistical distribution, or as a distribution of discrete variables such as a number of years of historical resource availability.
- Alternatively, seasonal accredited Capacity Contribution or some time referred to as the Effective Load Carrying Capability (ELCC) for variable resources should be used in the model. At least two values, one for the defined summer period and one for the defined winter period, can be used in the probabilistic assessment.
- Each Assessment Area should document how each of these resources are modeled and what data is used. PAITF recommends that each Assessment Area:
  - Describe how the ELCC or Capacity Contribution calculation is modeled across the year. If available, monthly or seasonal ELCCs, Capacity Contribution Calculations, or per-unit wind and/or solar generation profiles, based on history, for each significantly different wind or solar patterned zone in each Region/Assessment Area should be modeled.
  - Provide the justification and methodology for the determination of the probability distribution function and seasonal accredited values for VER.

Energy-Limited Resource Modeling

- Each Assessment Area should document how each of the energy limited resources are modeled and what data is used:
  - The type of hydro modeling approach currently used.
  - The capacity amount that can be reliably maintained for at least one full hour—designate number of hours if stated capacity amount can be sustained longer than one hour.
  - The annual forced outage rates, based on history, incorporating units impound times.
  - Storage maximum capacity in MWh values incorporating impound and discharging times.
  - The operating procedures for units' charging.

- For probabilistic assessment, water flows developed using historical data. The water flow can be treated as a random variable with a certain distribution and can be treated either as a continuous random variable using probability distribution function (PDF) or as a discrete random variable using probability mass function (PMF). The PDF and the PMF can be developed with reference to the historical water flows.
- Each Assessment Area should document in detail the justifications and methodologies for the development of the PDF/PMF, determination of the probabilities of different water conditions, and the modeling of hydro unit as an equivalent thermal unit
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Behind-the-meter Generation (BTMG)

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- The narrative needs to detail how each Assessment Area treats the BTMGs, either as a resource or a load modifier, etc. and how they insure that the BTMGs are not double counted.
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    - Summarize all other EOP types, the amount of relief, and how the amount obtainable is determined.
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- If it is not modeled, PAITF recommends that each Assessment Area supplies thorough documentation explaining why they have decided not to model EOP, and summarize the impact this decision has on the probabilistic assessment results.

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- Internal and external modeling constraints need to be addressed.
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Sensitivity & Scenario Modeling

- The sensitivity modeling should be addressed within the Core Probabilistic Assessment framework. NERC RAS identifies the variable data elements relevant to each sensitivity modeling.
- The scenario modeling should address the reliability issues identified within the LTRA that impact resource adequacy, within the Special-Coordinated Probabilistic Assessment framework. NERC ERO-RAPA and the PC identify reliability risk issues for scenario analysis, and NERC RAS evaluates input parameters relevant to each candidate scenario.