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Planning Committee Reliability Guidelines

Reliability Guidelines

Reliability Guidelines\(^1\) are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances\(^2\).

Approval of Reliability Guidelines

Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by a technical committee. The process described below will be followed by the Planning Committee:

a) **New/updated draft guideline approved.** The Planning Committee approves release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

b) **Post draft guideline for industry comment.** The draft guideline is posted for industrywide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.

c) **Post industry comments and responses.** After the public comment period, the Planning Committee posts the comments received as well as its responses to the comments. The committee may delegate the preparation of responses to a committee subgroup.

d) **New/updated guideline approval and posting.** A new or updated guideline which considers the comments received, is approved by the sponsoring technical committee and posted on the NERC Web site. Updates must include a revision history and a redline version against the previous version.

e) **Guideline updates.** After posting a new or updated guideline, the Planning Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.

   i. Each quarter, the Planning Committee will review the comments received. At any time, the Planning Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.

   ii. Updating an existing guideline will require that a draft updated guideline be approved by the Planning Committee in step “a” and proceed to steps “b” and “c” until it is approved by the Planning Committee in step “d.”

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\(^2\) Standards Committee authorization is required for a reliability guideline to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC’s *Rules of Procedure* under “Supporting Documents.”
Guidebook Overview

Background

The NERC Planning Committee agreed at their February 2008 meeting that a Reliability Assessment Guidebook should be developed to support the enhancement of seasonal and long-term reliability assessments. The goals of this Guidebook are to:

- Improve consistency and transparency of assessments
- Provide for more granular assessments
- Outline the process to assess emerging industry issues
- Establish a core framework for NERC when conducting comprehensive and independent assessments

This Guidebook provides a reference for regional entities and registered entities, and is organized to clarify current reliability assessment practices and objectives. The intent is to document practices and provide a comprehensive review for reliability assessments. The Guidebook reviews the elements and issues that go into making the NERC reliability assessments and the final NERC reports as consistent, uniform and credible as possible by explaining the need for:

1. Input from the Regional Entities, so that external audiences (e.g., FERC, media, Congress, CEOs, etc.) can obtain a clear understanding about the anticipated performance, strength and concerns of the bulk-power system over seasonal and long-term periods.

2. NERC’s and the Regional Entities’ assessments are presented in a consistent and conforming manner, so the overall reports are effectively comprehensive and complete.

The Regional Entities will develop the foundation and support for assessment practices, and as such, the Guidebook articulates the corresponding foundation, support and recommendations for the NERC independent review, providing a uniform delivery of the reliability assessment. The Reliability Assessment Guidebook is not a standard or requirement. The recommendations and guidance discussed are not enforceable as requirements under any NERC Standard.

Members of the Reliability Assessment Guidebook Task Force

- Tom Burgess (Chair)
- Jeff Mitchell (RFC)
- Chris Smart (WECC)
- Bob Williams (FRCC)
- Ed Weber (MRO)
- Bill Bojorquez (RAS Chair)
- Randy Hubbert (DCWG Representative)
- Mary Johannis (RIS Chair)
- Mark Lauby (NERC)
- John Moura (NERC)
Reliability Assessment Guidebook Lifecycle

The Reliability Assessment Guidebook is a “living” document and as Planning Committee Reliability Guideline it will be updated, as applicable per the Planning Committee Charter. The Reliability Assessment Guidebook Task Force will continue to collect comments. The task force will them respond to the comments and post them on the NERC website at: http://www.nerc.com/filez/ragtf.html. Each quarter, the Planning Committee will review the comments received and revise the document as needed.

Figure 1: Reliability Assessment Guidebook Lifecycle
Chapter 1—NERC Reliability Assessment

The North American Electric Reliability Corporation’s (NERC) mission is to ensure the bulk power system in North America is reliable. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future adequacy; evaluates owners, operators, and users for reliability preparedness; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that form its various committees and sub-committees. It is subject to oversight by governmental authorities in Canada and the United States (U.S.).

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight regional areas. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada and a portion of Baja California, Mexico.

NERC’s primary role in providing reliability assessment is to identify areas of concern to the reliability of the North American bulk power system and to make recommendations for their remedy. NERC cannot order construction of additional generation or transmission or adopt

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3 The part of the overall electricity system that includes the generation of electricity and the transmission of electricity over high-voltage transmission lines to distribution companies. This includes power generation facilities, transmission lines, interconnections between neighboring transmission systems, and associated equipment. It does not include the local distribution of the electricity to homes and businesses.

4 On June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards with all U.S. owners, operators, and users of the bulk power system, and made compliance with those standards mandatory, as opposed to voluntary. NERC has similar authority in Ontario and New Brunswick, and is seeking to extend that authority to the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.

5 Section 39.11(b) of the U.S. FERC’s regulations provide that: “The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission.”
enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Energy Policy Act of 2005. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

The Seasonal Reliability Assessments and Long-Term Reliability Assessment (LTRA) provide key findings, a high-level assessment of future resource adequacy, an overview of projected electricity demands and demand response resources, planned and proposed generation and transmission additions, emerging issues and their potential reliability impacts, operational reliability trends, regional assessment highlights, scenario analysis update and regional self-assessments. The LTRA represents NERC’s independent judgment of the reliability and adequacy of the bulk power system in North America for the coming ten years.

A distinction must be made to the recommendations outlined in this Guidebook for Reliability Assessments. This Guidebook serves as guidelines for assessing resource adequacy, as done by the Regional Entities and NERC. These guidelines do not attempt to support assumptions, models, methodologies used by entities responsible for determining (i.e. setting) resource adequacy requirements for their respective jurisdictions. The two activities are distinctly different in nature, although they may share some commonality (for instance, regarding the analytic tools used).

Assessment Preparation

NERC prepares the Seasonal and Long-Term Reliability Assessments with support from the Reliability Assessment Subcommittee (RAS) under the direction of NERC’s Planning

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7 Unlike the Energy Information Administration’s (EIA) Annual Energy Outlook (for example the 2008 report can be found at http://www.eia.doc.gov/oiaf/aeo/pdf/0383(2008).pdf), NERC’s report focuses exclusively on bulk power system reliability with data and information provided by industry experts, representing a variety NERC stakeholders.
Committee (PC), shown in Figure 2. The reports are based on data and information submitted by each of the eight regional entities submitted in March, May and September each year and periodically updated throughout the process. Instructions on data submittal and timely subjects for group development within the self-assessments are provided to each regional entity approximately three-to-five months prior to submittal of the data and narratives. Any other data sources consulted by NERC staff are identified in the report.

NERC uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the information provided by the Regional Entities.

Each region prepares its data and a self assessment. Each of the regional self-assessments is assigned to two-to-four RAS members from other regions for an in-depth and comprehensive review of the data and information. Reviewer comments are discussed with the regional entity’s representative and refinements and adjustments are made as necessary. The regional self-assessments and data are then subjected to scrutiny and review by the entire subcommittee. This review ensures members of the subcommittee are fully convinced that each regional self-assessment and data is accurate, thorough, and complete. The Reliability Historical Trends section is reviewed by the Operating Committee (OC), while the entire document, including the regional self-assessments, is then reviewed in detail by the Member Representatives Committee (MRC) and NERC management. The report is endorsed by the PC before being submitted to NERC’s independent Board of Trustees for final approval (See Appendix II for organization charts). This comprehensive vetting process insures complete stakeholder agreement on NERC’s independent assessment and the self-assessment from the Regional Entities, as well as supports the mission of NERC as a self-regulatory organization.

For NERC’s Seasonal and Long-Term Reliability Assessments, the baseline information on future electricity supply and demand is based on several assumptions:

- Supply and demand projections are based on industry forecasts submitted by a certain date. Any subsequent demand forecast or resource plan changes may not be fully represented.
- Peak demand and reserve margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each regional self-assessment.
- Generating and transmission equipment will perform at historical availability levels.

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8 See [http://www.nerc.com/files/concepts_v1.0.2.pdf](http://www.nerc.com/files/concepts_v1.0.2.pdf) for more background on reliability concepts used in this report.

9 Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year’s actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower.

For planning and analytical purposes, it is useful to have an estimate not only of the expected of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the Load Forecasting Working Group (LFWG) develops for each an upper and lower ten percent confidence band around the NERC regional demand and energy projections. This means there is an 80 percent probability that future demand and energy will occur within these bands. Concurrently, there is a ten percent chance future outcomes could be less than the lower band and a ten percent chance future outcomes could be higher than the upper band. The high and low bands around the demand forecasts are depicted in the charts with each region's self-assessment.
- Planned outages and future generation and transmission facilities are commissioned and in-service as scheduled and planned.
- Demand reductions expected from demand response programs will yield the forecast results, if and when they are called on.
- Other peak demand-side management programs are reflected in the forecasts of net internal demand.
- Firm electricity transfers between regions are contractually arranged and occur as projected.

NERC basis for an independent assessment is the data submitted to NERC from the Regional Entities. The high level demand and supply data collection process, for reliability assessments, is shown in Figure 3. All NERC Regions, including Canada and Mexico, provide their demand and capacity resources information to NERC through the LTRA data collection process, which is then submitted to EIA on behalf of the industry through the EIA-411 Data Form.

The Form EIA-411\(^\text{10}\), “Coordinated Bulk Power Supply Program Report,” collects information from the North American power system planners about the electricity supply, both capacity and energy, that is needed to serve current demand and for future growth. In 2008, the Form EIA-411 became a mandatory collection for all schedules except No. 7 (Transmission Outages) which will continue to be a voluntary filing. This data can be used to examine such issues as: the reliability of the U.S. electricity system; projections which assess future demand growth and plans for constructing new generating and transmission facilities; and consequences of unavailable or constrained capacity on usage of the existing generation base.

Generator Owners and Operators provide specific generator data to EIA through the EIA-860 Form\(^\text{11}\), which is then provided to NERC. The Form EIA-860 is a generator level data file that includes specific information about generators at electric power plants owned and operated by electric utilities and nonutilities (including independent power producers, combined heat and power producers, and other industrials). The database contains generator-specific information such as initial date of commercial operation, prime movers, generating capacity, energy sources, status of existing and proposed generators, proposed changes to existing generators, county and State location, ownership, and FERC qualifying facility status.

For Canadian and Mexican organizations, NERC has a process to collect specific generator data. This is incorporated into the LTRA data collection forms on an annual basis. These forms mimic those found on the Form EIA-860. This data is submitted directly to NERC.

\(^{10}\) More information on the Form EIA-411 can be found at: [http://www.eia.doe.gov/cneaf/electricity/page/eia411/eia411.html](http://www.eia.doe.gov/cneaf/electricity/page/eia411/eia411.html)

\(^{11}\) More information on the Form EIA-860 can be found at: [http://www.eia.doe.gov/cneaf/electricity/page/eia860.html](http://www.eia.doe.gov/cneaf/electricity/page/eia860.html)
Once all data is compiled, it is used to populate the Electricity Supply & Demand database. NERC maintains and annually publishes electricity supply and demand information for North America encompassing both current and historical long-term capacity and demand projections. ES&D data include aggregated ten-year projections of electricity demand, electric generating capacity, and transmission line mileage that the NERC Reliability Assessment Subcommittee (RAS) uses in their annual long-term reliability assessments of the interconnected bulk electric system in North America. In addition the data includes unit-specific statistics on existing generators, planned generator additions and retirements, and proposed equipment modifications.

A high level annual schedule for the NERC reliability assessments is shown in Figure 4.

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12 A detailed glossary of terms used regarding the EIA-411 data submittal can be found at http://www.eia.doe.gov/glossary/index.html
Figure 4: NERC Reliability Assessments Schedule
The bulk power system is made up of three main parts: generation, transmission, and load (i.e. customer electric demand). The electric industry uses terms such as reliable, unreliable, or system reliability as qualitative measures of the relative strength or balance of the bulk electric system. Reliability is the term used by the electric industry to describe and measure the performance of the bulk power system. It is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be quantitatively measured by the range of operating conditions under which the system performs within acceptable parameters.

Meeting the reliability expectations of consumers requires the bulk power system to be planned, designed, constructed, operated, maintained, and restored (as necessary following the loss of electric infrastructure) as described by specific, pre-determined tests or criteria. As such, the bulk power system is constantly evaluated, assessed, and planned to ensure that an adequate supply of electricity is available and deliverable and that the capacity and the capability required meeting current and future needs is sufficient. More background on current industry practices and approaches, summarized from the recent Resource Issues Subcommittee’s (RIS) survey can be found in Appendix I.

Guidelines for Long-Term Planning

Long-term power system planning encompasses the development, evaluation and assessment of various potential outcomes for one or more years into the future. Operational planning can and does use similar concepts as long-term power system planning except that the focus is the time period between one day and one year into the future. Both long-term and operational planning must address the uncertainty in the assumptions, such as forecast load, generation dispatch, the status of transmission elements, and regional assumptions affecting loop flows, all of which define the operational state of the network. The primary difference between long-term and operational planning is in the range and types of uncertainty that must be addressed.

The dictionary defines reliability as consistently dependable performance. The reliability of the bulk power system is based on adequacy, having the necessary generating capability and transmission line capacity, and operating reliability, the ability to meet demand under forecast and unforeseen conditions. Both characteristics are necessary to provide a desired level of reliability. Power system planners consider several metrics under different scenarios in the design and testing of the bulk power system to meet minimum reliability levels.

13 Section 215 of the Federal Power Act does not give NERC authority over the distribution system and it is only load which is referenced in the FPA. NERC is not authorized to address reliability performance of the distribution system.

14 Transmission Elements as defined by the TADSTF. More information can be found in the TADS Phase II Final Report http://www.nerc.com/docs/pc/tadstf/TADS_Phase_II_Final_Report_091108.pdf
Generators and transmission elements are the building blocks of the bulk power system. The number and configuration of generators and transmission lines contribute to the reliability of the bulk power system. The planning process assesses the performance of the existing bulk power system with respect to various reliability objectives to determine its ability to meet forecast requirements with adequate reliability. Such objectives and methods are typically described as either deterministic or probabilistic. Each defined as:

- **Deterministic** reliability measurements have traditionally been applied to test the ability of the Bulk Power System to meet acceptable performance metrics for different contingent states, for example the ability to operate within applicable limits and ratings for an N-1 contingency event.

- **Probabilistic** methods have traditionally been applied in resource adequacy planning and use characteristics of system components to predict the likelihood that demand will be served.

Deterministic and probabilistic are different and complementary methods to analyze bulk power system reliability. A deterministic analysis is based on a set of general assumptions regarding the nearly infinite number of variables which define an operating state of the bulk power system. These include the status of generating units and transmission elements, weather conditions to define facility ratings and forecast load, regional load diversity, generation dispatch and net scheduled interchange. Having defined assumed operating state events which are considered credible based on past performance and which tend to be associated with a change in status of generating units and/or transmission elements are identified for assessment to determine their impact on reliability. Judgment is used to determine how many coincident or simultaneous credible events will be considered, what levels of sensitivity analysis will be included for the variables that define the operating state, and what types of mitigation, if any, will be required to provide acceptable levels of reliability.

Probabilistic analysis describes events in terms of how probable they are, and requires knowledge of the performance characteristics of the components of the bulk power system. Measurement of past performance of the bulk power system can be expressed precisely in terms of frequency, duration, and the number of elements affected in past events. Measurement of future reliability is not as precise, and 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 bulk power system. Probabilistic methods typically rely on either statistical analysis of historical performance of system elements to identify the system scenarios/events to simulate or enumeration techniques which are capable of simulating large numbers of contingencies up to a specified n-k depth. 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. Further, based on the number of variables and the number of variable states, it can be challenging to perform a statistically significant sample to have acceptable confidence in the results.

Industry practices generally incorporate both deterministic and probabilistic methods. It should be noted, though, **the requirements of the current NERC Standards are deterministic in nature.**
System Reliability Characteristics & Guidelines for Bulk Power System Planning

Two fundamental and measurable characteristics of bulk power system reliability, proposed by NERC\textsuperscript{15}, are a vital foundation for the concepts described in this document:

- **Reliability**: in a bulk power system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability in operations may be measured by the frequency, duration and magnitude of adverse effects on consumer service. The degree of reliability in operational and long-term planning is measured by the predicted performance of the system in studies to provide acceptable performance for credible contingencies while considering sensitivity in the assumptions that define the operational state being studied.

- **Adequacy** is the ability of the bulk power system to supply the aggregate power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of the system components

- **Operating Reliability** is the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components

Planning the transmission system requires four major ingredients:

1. **Load forecast**: The load forecast is developed in a variety of ways using a variety of assumptions, econometric models and statistical information. System planners incorporate such load forecast in the transmission base cases and conduct analysis to identify generation and transmission expansion needs to meet demand.

2. **Generation and transmission plans already in place**: The system planner needs to accommodate those generation and transmission facilities that are either planned or are in various stages of construction. These plans include independent power plants, and power plants and transmission lines in other electrically related areas.

3. **Planners learn from system operators**: System planners benefit from learning 1.) Which contingencies are likely, and 2.) How the Interconnection actually performs following real contingencies.

4. **Planning criteria**: For many years, NERC published collections of the regional planning criteria (see Bibliography), and from those criteria, developed the current planning standards—specifically, the Transmission Planning (TPL) series.

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Design Standards play an essential role in preventing major system disturbances following severe events. Bulk Power System planners deal with future systems that are only “operated” in system simulation studies. Since planners cannot simulate all single-element outages under various system conditions, they simulate two types of contingencies as part of their design criteria for new transmission facilities: the single-element (N-1) contingencies, and multi-element contingencies (e.g., a single line-to-ground fault on a bus section, which may remove several circuits from service.). In planning studies, the performance expected for multi-element outages may include loss of firm load, but the resulting disturbance is designed not to cascade and the system must remain stable, within the applicable ratings for thermal and voltage limits.

Planners normally model both single-element (N-1) contingencies, and multi-element contingencies, usually assuming no other element forced outages. Experience has shown that simulated transmission systems withstanding both single and multi-element contingencies are capable of withstanding single-element contingencies in a real-time operating environment with other elements out of service. Withstanding multi-element contingencies is a planner’s way of providing bulk power system operational margins for system operators, compensating for the planning assumption of “all lines in-service.”

Planners do not know what the construction schedules might be in the future and what will be out of service at any point in time. Therefore, the starting point to analyze reliability is different than operational studies. In order to test the bulk power system, additional outages/contingencies are simulated to test the system robustness. Long-term planners can not study all possible starting conditions or all potential hours of operation. Therefore criteria were develop to test the bulk power system so the resulting designed system can be operated with the operational margins needed for all the conditions a planner never studied. Planners provide additional operational margin by simulating several different system conditions, transfer levels, load levels, and generation dispatch scenarios. These scenarios, in combination with the contingency analysis for single- and multi-element outages, establish the requirements for future transmission facilities.

Planners evaluate extreme contingencies involving two or more element outages of an extreme nature. These contingencies may lead to cascading outages and system instability. Extreme contingencies are assessed to determine their consequences only; transmission facilities are not constructed to avoid the consequences of extreme contingencies.

Guidelines for Reliability Assessment

Reliability assessment is the process of investigating plans of future adequacy and operating reliability of the bulk power systems. It may involve comparison of expected system performance with specific criteria to identify possible weaknesses, or it may be more general expression of potential problems. Extensive planning criteria and assessment approaches have been developed by the electric industry in North America. Assessment procedures test bulk power systems against a variety of measurements/criteria to provide confidence that foreseeable weaknesses of the studied bulk power system are identified. Since generation and transmission planning of any utilities are affected by the plans of other interconnected electricity suppliers,

many of these criteria have now become NERC\textsuperscript{17} or regional entity mandatory performance Standards.

NERC has been pursuing an improved definition of adequacy to address both the issues of sufficient generation capacity and its delivery to end users. One way of addressing this larger definition of adequacy is to define it in terms of how uncertainty is dealt with in the various planning processes. Adequacy becomes a measure of the level of confidence the operator and planner have that the bulk power system as modeled in studies can meet performance requirements in real time.

The measurement of bulk power system reliability is intended to ascertain the capability of the system. It may also identify thresholds of unreliability by examining increasingly severe conditions. Simulated deterministic testing and probabilistic studies are means of assessing how the performance of a proposed system compares with reliability objectives. Such examinations must be executed in a structured and consistent manner facilitating comparisons both through time and throughout the bulk power system.

Bulk power system contingency criteria (for example, the NERC Transmission Planning or TPL Standards, Table 1,\textsuperscript{18} categories A, B, C & D) have been developed for nearly half a century, their development beginning when computer software enabled simulation and evaluation. Experience has showed that if certain deterministic tests of the system (criteria) were met in conjunction with system sensitivity assessments (such as incremental transfer capability studies) the system as designed, when built, would have suitable planning margins to meet the multifarious conditions faced by operators. If planners met the established criteria with consideration to system uncertainty; operators would have a system that could be operated with acceptable performance even if the conditions differed significantly from those assumed by the planners.

For reliable service, a bulk power system must remain intact and be capable of withstanding a wide variety of events and disturbances\textsuperscript{19} over a wide range of system operating conditions. Therefore it is essential that a system be designed and operated so that the more probable events (sometimes called contingencies) can be sustained with no loss of firm load (except that connected to the faulted element) and so that the most adverse possible events do not result in uncontrolled, widespread and cascading power interruptions.

Guidelines for Sufficient Planning Margins supporting Operating Reliability & Adequacy

The industry measures the \textit{operating reliability} of the future bulk power system to deliver power and energy by noting the response of future systems scenarios (through simulation) when subjected to a variety of contingencies or severe disturbances. NERC Standards define a wide range of contingency states (see Transmission Planning Standards\textsuperscript{20} TPL-001-0 through TPL-

\begin{itemize}
\item \textsuperscript{17} http://www.nerc.com/files/Reliability Standards Complete Set 1Dec08.pdf
\item \textsuperscript{18} http://www.nerc.com/files/TPL-001-0.pdf
\item \textsuperscript{19} Power System Stability and Control, Dr. Prabha Kundur, McGraw Hill, 1993.
\end{itemize}
Planning studies combine contingency analysis with sensitivity analysis of the results to system state conditions to assess overall system adequacy. Although there is no guarantee that major disturbances cannot or will not happen, the assessment procedures do provide reasonable assurance that the system as designed will ultimately be capable of being operated with an acceptable level of reliability over a sufficient range of operating states.

Likewise, the industry can measure the adequacy of the future bulk power system to meet forecast demand by comparing generation energy and capacity to forecast net internal energy and peak demand. This comparison may incorporate a consideration of the bulk power system’s ability to deliver energy requirements. Each generator is typically described with a capacity and energy component along with a probability or other indication of its availability. The forecast internal demand and network requirements are many times described by a peak demand, a pattern of demands or a variety of scenarios with a distribution of uncertainties. Comparing generation capacity/energy with a variety of forecast internal demands/energy requirements using a range of probabilities and uncertainties, results in a measure of future bulk power system adequacy. This assessment approach can be augmented with additional parameters provide boundaries to the bulk power system deliverability of capacity/energy between groups or individual resources and load.

The assessment of both the security and the adequacy of the bulk power system are dependent on how uncertainty related to the assumptions associated with the description of the operating state(s) studied is addressed. This uncertainty can include variations in local load forecast and generation dispatch, the affect of loop flows caused by diverse regional weather and load patterns, and changes in the assumed status of existing and planned generators and transmission elements. The nature and affect of uncertainty vary with respect to the time frame of the reliability assessment. Uncertainty in the bulk power system conditions for real time studies 10 minutes into the future, are confined to variations in the status of equipment. Operational planning studies for the seasons ahead and long-term planning studies 10 years into the future must address uncertainties associated with the multitude of variables that define the assumed operating state(s) of the bulk power system in addition to changes in the status of system components.

Beyond meeting pre-specified criteria, planners in most organizations perform sensitivity analysis in conjunction with the TPL pass/fail tests to measure the resulting relative security and adequacy planning margins. System sensitivities are measured by applying and simulating a multitude of transfers (import/exports) and system conditions (load levels and transmission/generation conditions), based on past experience and engineering judgment. These additional tests identify insufficient planning margins, based on each organization’s specific system conditions and their desired final reliability level. Additional planning margins are then built into the system to fortify the bulk power system preparing for the time the system will be ready for operation.
Definition of “Adequate Level of Reliability” \(^{21}\)

The bulk power system will achieve an adequate level of reliability when it possesses following characteristics:

1. The System is controlled to stay within acceptable limits during normal conditions;
2. The System performs acceptably after credible Contingencies;
3. The System limits the impact and scope of instability and cascading outages when they occur;
4. The System’s Facilities are protected from unacceptable damage by operating them within Facility Ratings;
5. The System’s integrity can be restored promptly if it is lost; and
6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

The Bulk Power System exhibits an adequate level of reliability when it possesses these six characteristics. Some of the terms such as “acceptable limits” and “acceptable performance” require specificity in order to be applied.

**Metrics**

The definition of adequate level of reliability is broad enough to apply to all possible NERC standards, and therefore it is not based on specific metrics. However, NERC will develop metrics at the System level that will track performance of these characteristics. These System performance metrics will be different from measurements in a NERC standard which are used to determine compliance. System performance metrics will provide feedback for improving the Reliability Standards. They will help identify reliability gaps and point to existing standards that need to be modified or new standards that need to be developed.

**Cost effectiveness**

The definition of adequate level of reliability does not mention any specific measure of “cost effectiveness” because costs versus benefits, including societal benefits, can only be determined by the individual users, owners, and operators. They will have different perspectives on what is “cost effective” for them, and they will exercise their judgments by participating in the standards drafting process, and ultimately, when they cast their ballots to approve or reject a standard. \(^{22}\) A goal of the standards is to achieve an adequate level of reliability across North America. For various reasons, some users, owners or operators and their Regional Entities may choose to plan and operate their portion of the

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\(^{21}\) This is a high-level summary of NERC’s description of “Adequate Level of Reliability” or ALR. More detail can be found in on NERC’s website [http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-PC-PC-mtg.pdf](http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-PC-PC-mtg.pdf)

\(^{22}\) In the NERC Rules of Procedure, Section 302 (3) addresses performance requirements for standards and references “costs and benefits.” It states: “Each [performance] requirement is not a “lowest common denominator” compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.” These “cost and benefits” are not explicitly developed. Ultimately, the ballot body, which decides on standards, decides on its cost effectiveness.
System to achieve a level of reliability that is in excess of the requirements of the NERC the standards.

Summary

Power System Planning related analysis generally results in a series of scenarios of projected future conditions along with stressed conditions and capacity evaluations to measure the system reliability compared with a variety of approved NERC and regional entity Standards. The system is designed to accommodate a wide range of generation patterns, internal demand and network flows. The resulting plan includes sufficient planning margins which translate into suitable operational margins providing acceptable performance across a range of uncertain future conditions, while balancing reliability and economics.
Chapter 3—Demand and Load Forecasting

The peak demand projections represent an aggregate of weather-normalized regional projections. In some cases, these regional aggregations do not take into account the regional diversity among the various regional participants’ peak demands, which, depending on the geographical size, could significantly influence the reserve margin comparisons. However, in other cases, as regions can be wide-spread, resources would not be deliverable across regions, and sub-regional analysis is more meaningful. The following defines demand terms used in NERC’s reliability assessments.

**Total Internal Demand:** Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).

**Standby Demand:** The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer’s primary source. Standby Demand is intended to be used infrequently by any one customer.

**Net Internal Demand:** Equals the Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

**How Regional Entities Develop their Load Forecasts**

Forecasts cannot precisely predict the future. Instead, many forecasts report a baseline or most likely outcome, and a range of possible outcomes based on probabilities around the baseline or midpoint. Each of NERC’s Region Members is responsible to provide demand forecasts for the Long-Term Reliability Assessment. Each regional demand forecast, for example, is assumed to represent the expected midpoint of possible future outcomes. This means that a future year’s actual demand may deviate from the midpoint projections due to variability in key factors that drive electrical usage. In the case of the NERC regional forecasts, there is generally a long-run 50% probability that actual demand will be higher than the forecast midpoint and a long-run 50% probability that it will be lower.

In order to evaluate the assumptions and load forecast data consistency of internal demand data submitted to NERC for its Seasonal and Long-Term Reliability Assessment, the Load
Forecasting Working Group (LFWG) developed a survey to gather load forecasting approaches used by the Regions and Load Serving Entities (LSE). Based on the results of this NERC Load Forecasting survey, trends were recognized regarding how regional entities develop and submit their Seasonal and Long-Term Reliability Assessment 50/50 load projections:

- Most forecast data comes from the Independent Service Operators/Regional Transmission Organizations, and Load-Serving Entities
- Four of the regions/sub-regions sum non-coincident peaks, three combine coincident peaks, and two adjust the sum of non-coincident peaks for diversity.
- Internal demand diversity is not reflected in submittals from four regional/sub-regional entities, while others utilize varied approaches to address diversity when peaks are summed.
- Five of the regions/sub-regions do not include behind-the-meter generation in their forecasts, while others either incorporate it into the estimated aggregate or indicate it with specific detail.
- The majority of the regions/sub-regions includes direct control and/or contractually interruptible programs, though three do not.
- Roughly equal numbers of regional/subregional entities report that the impact of future energy efficiency is implicitly included as not reflected.
- Standby demand is included in the forecasts of three regions/subregions, while the rest do not report it.
- The majority of regions/sub-regions deploy models using actual loads in the estimation period, though forecasts/simulations produce weather-normalized values. Three regions/subregions deploy models which use weather-normalized loads in the estimation period.
- A variety of approaches are used to ensure all load is counted, but not double-counted, for load forecasting purposes. They range from all internal demand being within the regional/sub-regional control area to delegating this responsible to the load-serving entity.
- Most regions model uncertainty explicitly by high/low projections, two use alternate “point” while others use Monte Carlo or explicitly address uncertainty by varying model inputs.

Based on the results from this survey, the LFWG concluded that there is sufficient inconsistency in forecasting methodologies across the regions that the reported data are not comparable. LFWG considered, but rejected, standardizing forecasting methods across all reporting entities. Such standardization could be overly burdensome and unlikely to produce better forecasts. In order to increase the understanding of the significance of the differences between load forecasts, and increase accuracy, the LFWG recommends that the collection and reporting of load data should be revised to:

- Broaden the information on projected demand-side management
- Understand the forecast regional diversity factors, and
- Account for non-member load included in the forecast

The summary below should be used as an abstraction of these goals, included in the Seasonal and Long-Term Reliability Assessment data collection forms:

<table>
<thead>
<tr>
<th>Item</th>
<th>Add/Subtract</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Unrestricted Non-coincident Peak</td>
<td>+ (Starting Point)</td>
</tr>
<tr>
<td>2. New Conservation (Energy Efficiency)</td>
<td>-</td>
</tr>
<tr>
<td>3. Diversity</td>
<td>-</td>
</tr>
<tr>
<td>4. Stand-by Demand</td>
<td>+</td>
</tr>
<tr>
<td>(Normally served by behind the meter generation)</td>
<td></td>
</tr>
<tr>
<td>5. Additions for non-member load</td>
<td>+</td>
</tr>
<tr>
<td>6. Total Internal Demand</td>
<td>Sum</td>
</tr>
<tr>
<td>7. Dispatchable, Controllable Demand Response</td>
<td>-</td>
</tr>
<tr>
<td>8. Net Internal Demand</td>
<td>Sum</td>
</tr>
</tbody>
</table>

While the above reporting framework will not obviate differences in forecasting methods, the differences will be readily visible. For example, for regions directly adding non-coincident peaks, no diversity will be reported while regions reporting coincident forecasts will report a diversity value.

This enhanced reporting framework, implemented in the NERC Seasonal and Long-Term Reliability Assessment data collection process, increases the granularity embedded within demand data. The resulting components must be further examined to determine what assumptions are being taken when load forecasts are developed.

**Guidelines for Modeling of Demand**

Appropriate load representation for resource adequacy analysis can be quite simple, but needs to be sufficiently detailed to permit the analysis to cover all of the relevant risk factors. At the same time, load representation also needs to be streamlined enough to permit solving the analysis in a reasonable time. A detailed discussion of resource adequacy assessment methods is included in Appendix I.

It is important to model load uncertainty. Weather-related load uncertainty may be modeled by depicting load as a stochastic parameter in the probabilistic analysis. Economic-related load uncertainty, which is typically longer term, i.e. over a 10 to 20 year period, can be modeled using scenario analyses. Modeling of load correlations between transmission areas or across days due to a heat wave or cold snap is also usually more important than the modeling of the typical daily or weekly load shape.

**i) Single Area Issues**

Load representation must be sufficiently detailed to capture all times and events which may cause loss of load. The representation of load variation due to weather, short-term economic conditions and other factors is the most important factor in resource adequacy analysis. Load shape factors only become significant after weather or economic conditions have driven demand (relative to supply) up to levels with a high risk of loss of load. In thermal systems or those with little energy-limited generation, each day may be considered independent. For the most part, equivalently increasing the number of trials performed increases the number of peak loads that are tested. In the limit, the range of
peak loads can be described as a distribution of peak loads. Therefore, uncertainty in daily peak loads can then be reduced to the distribution of daily peaks.

If (1) the risk of loss-of-load (LOL) only occurs in contiguous hours around seasonal peak, (2) there are no transmission limitations in the area and (3) no resources are limited by such things as time of day, energy, or number of occurrences, a simple probabilistic distribution of seasonal peak may be sufficient. Traditional analytical convolution of this distribution with the distribution of available capacity is adequate for this analysis. Unfortunately few systems are this simple anymore. However, in many cases, such simplified modeling techniques are still used to represent the more complex system.

For energy-limited systems, the sequence of load over a few days, a week, season or even multiple years may be significant because of the draw-down of energy stores such as hydro-based energy in reservoirs. A full representation of uncertainty may be impractical. No one technique has been shown to be the best in these situations.

Appropriate load shape for analysis (usually an 8760 hourly annual load shape) are typically selected for patterns of load across days rather than patterns of loads within days. The diurnal load cycle is usually well-defined and only in a few instances an important factor in resource adequacy. Appropriate modeling of heat or cold waves is a main consideration. Annual load cycles may be important if resource scheduled maintenance may interact with load to create LOL events during typical maintenance periods during low load (spring and fall) periods.

The load representation should be typical and not an average which has smoothed out all of the volatility that can be expected in future loads. Some aspects of weather variation are included in the design of the hourly load shape to be used in reliability studies. Using the hottest year on record does not necessarily provide the most conservative answer once it is input into the resource adequacy assessment model and adjusted to represent a future year by scaling the peak load in the historical year to the peak load in the future year. For example, if the peak loads in the “hot” historical year are much higher than those of the other days and this profile is scaled up to a normal weather year, then all the non-peak days will be scaled up, but will remain much lower than the forecast peak load. LOL occurrences then will be concentrated on only the “hot” day and not on the other days.

The representation of hourly load and all of the various types of uncertainty must work together to represent the combined distribution of load. The combined load representation (as created in the model is best) should be checked to ensure it is appropriate. If uncertainties are not recognized, one may require additional resources to achieve a reliable system. Double accounting of uncertainties results in a more reliable system, but at the cost of paying for additional, perhaps unneeded resources.

ii) Multiple Area Issues

If transmission limitations within the area impact resource adequacy or if support from other areas is to be considered in the analysis, it is necessary to implicitly or explicitly model the load shape and uncertainty within multiple areas and the correlation of uncertainties and base characteristics between or among areas.
Each area has all of the modeling challenges described under single area issues. The correlation of all of the uncertainties and base load shapes across the areas must now be considered. How correlated is the weather across the multiple areas? Is the total analysis region large enough that the movement of weather systems through it should be modeled?

The more detailed the load representation the more difficult this is to model. Often the best that can be done is to select an hourly load pattern for all areas from one historic year determined to be the best representation of a typical year (not average and probably not extreme depending on the modeling of uncertainty). Because historical loads do not reflect the future year conditions exactly, they must be scaled. Whether the scaling is applied to all of the regions simultaneously or individually affects the amount of diversity incorporated in the load model.

Modeling all areas as peaking at the same time (day and hour) is conservative but may be the best alternative.

### iii) Demand Uncertainty Concepts

As is the case for probabilistic methods, in general, load uncertainty modeling techniques may be classified into two general categories:

- Load uncertainty represented as a distribution
- Load uncertainty representing historical patterns with diversity embedded

These techniques would be applied to a “base case” and different scenarios.

Analytical convolution may be an acceptable technique to use for load uncertainty that covers all possible events. Unfortunately, it becomes complicated when correlation of loads between areas or over time is considered. If all the information about weather related uncertainty is included in a load distribution for one area and all the weather related uncertainty is included in a load distribution for a second area, unless there is some correlation factor expressly included, the effects will be considered to be random and independent. (i.e. one area could be experiencing an extreme heat wave while the other area is experiencing unseasonably cool weather.) It also requires a similar resource uncertainty representation. For very simple systems, analytical convolution is fast and accurate, but it becomes too complex for multi-area systems. This technique is still appropriate under certain conditions.

For detailed multi-area simulations (with transmission constraints between areas or different emergency operating procedures), analyses using Monte Carlo simulations are generally performed for resource adequacy evaluations. Typical modeling of loads in multi-area models assume that weather uncertainty has common driving influences that will recognize that the highest weather related load uncertainty occurs in all areas simultaneously, while the lower than nominal loads in all areas also all occur simultaneously. The issue that is typically encountered when dealing with load models is computer solution time. A large number of trials are required because LOL events have low probability. The issue isn’t the ability to model load uncertainty or correlations but the estimation of appropriate uncertainty distributions and correlation (in time or between transmission zones) which are then input into the analysis.
Scenario analysis may be used in conjunction with either technique above. Scenario analysis is often used to complement Monte Carlo analysis. It is good for representing rare or complex events especially those which can’t be easily parsed into distributions and correlations, or those which would require too many trials to make sure they were captured in Monte Carlo analysis. For loads specifically, scenario analysis is often useful for economic forecast uncertainty or to model the impact of a significant load shape changing event (Such as climate change).

How NERC Develops its Load Forecast Bandwidths

For securing energy supply or ensuring reliability of the bulk power system, adequate risk management implies defining possible future outcomes and their probability of occurrence. For planning and analytical purposes, it is useful to have an estimate not only of the expected midpoint of possible future outcomes, but also of the distribution of probabilities around the projection. Accordingly, the NERC Load Forecasting Working Group (LFWG) develops upper and lower 10% confidence bands around the NERC regional peak demand and energy forecasts. This means that there is a long-run 80% probability that future demand and energy will occur within these bands. Conversely, there is a 10% chance that future outcomes could be less than the lower band, and a 10% chance that future outcomes could be higher than the upper band. A sample bandwidth analysis is shown in Figure 5.

Overview of Method - LFWG continues to introduce enhancements to the regional bandwidth methods. The previous method used first order autoregressive models for every region’s energy, summer peak, and winter peak. Although using a single statistical time-series model has merits and results were satisfactory, LFWG desired to investigate other approaches and model specifications for possible improvements or better model fits. The study by Brisson & Nadeau recommended an approach to find an optimal model for each Region and each series (energy, summer peak, winter peak).

The principal features of the regional bandwidth method include:

(1) The regional projections of demand and net energy for load are modeled as a function of past peak demand or energy. An optimal model is selected for each region’s energy, summer peak, and winter peak (33 models in all). The most frequent (17 out of 33) optimal model was the random walk model with drift specification. This approach expresses the current value of the time series as a linear function of the previous values of the series and a random shock.

(2) In cases where membership changes resulted in significant changes to a region’s energy and load, an intervention variable is added to the equation to allow the bandwidths to suitably depict post-change energy and load uncertainty. The historic variability observed in demand and energy is used to develop uncertainty bandwidths projections.

Each of the eight U.S. and three Canadian subregions is modeled separately with three regions segmented into their United States and Canadian counterparts. Irregular patterns of deregulation, different economic trends, and variable weather patterns contribute to the variability of actual peak demand and electricity usage. The response to these factors differs across regions due to different weather variation, economic conditions, energy prices, and regulation/deregulation policies. The bandwidths around NERC regional projections of long-term peak demand forecasts implicitly reflect the combined uncertainty from these factors. Accordingly, the bandwidth results on a region-by-region basis are unique.

**Results** - The bandwidths produced are theoretical bandwidths based on mathematical representations of the series. They are derived from in sample residuals (fitting errors) and 80% standard normal confidence intervals. Bandwidths obtained with the theoretical formulas are then proportionally projected onto the regional forecasts provided by the Regions.

**Guidelines for Demand-Side Management (DSM) Resources**

Demand-Side Management (DSM) is important ingredient of an overall portfolio of resources required to meet the increasing demands for electricity in North America. DSM is often understood to include two components: energy efficiency (EE) and demand response (DR). EE is designed to reduce electricity consumption during all hours of the year, attempting to permanently reduce the demand for energy in intervals ranging from seasons to years and concentrates on end-use energy solutions. DR is designed to change on-site demand for energy in intervals from minutes to hours and associated timing of electric demand/energy use (i.e. lowering during peak periods) by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs.

25 During the 1990s and 2000s several regions including MAIN, MAPP, MRO, RFC, SERC and SPP experienced changes in membership and geography. The historical net energy and peak load data and figures depict these changes.
DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand. They can be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with variable renewable resources.

DSM resources can be modeled in a variety of ways, all of which are appropriate. It is difficult to establish a “base” condition, as many times existing DSM resources have been embedded into the load forecasts for many years and, therefore, “new” DSM gathered and modeled. The following examples and discussion apply to the evaluation of DSM from new programs:

1. DSM as Reduction in Firm Load: DSM can be modeled implicitly as a reduction to the firm customer loads. If the loads can be expected to be reduced with a high degree of certainty, this would be an appropriate modeling technique. This technique would be most suitable for passive DSM such as conservation and energy efficiency, which does not vary significantly due to temperature.

   If expected load reductions are not as certain, due to either equipment performance, a load customer's willingness to perform (economic DSM), or significant temperature performance variability, then this uncertainty would need to be included in the underlying firm customer loads that need to be served.

2. DSM as a Resource: DSM can be modeled explicitly as a collection of different resource types with various performance characteristics described using capacity, associated forced outage rates and temperature sensitivities.

Regardless of whether DSM resources are modeled as a load reduction or as a supply side resource, the total amount of non-DSM resources would be constant in both frameworks if all the same uncertainties are accounted for in the reliability calculations. While the total amount of non-DSM resources would be the same, the numbers used for resources supply and peak load in the percent reserve margin calculations would be different and therefore the resulting reserve margin values would be different.

An issue with modeling and counting DSM resources is that physical equipment associated with the DSM is seldom countable for analysis and is under the control of distributed users for installation, activation and/or retirement. In addition many DSM resources are not solely equipment-based, but depend directly (rate response) or indirectly on customer behavior (industrial equipment is a resource only if it is in production to meet an industrial process). To further complicate analysis, some but not all DSM resources may be partially included in the reported existing load or into the load forecast. Also, what one area may consider DSM a resource another may consider a firm load. This complicates the comparability of whether an LOL Occurrence should be counted or not even if the two areas were compared using the same criterion.

In spite of the problems, DSM resources are legitimate resources to be included in current and future resource evaluations. In many cases, DSM resources have very long ‘construction’ periods before they reach their full capacity value but, contrary to supply resources they start to provide
benefits immediately. But because ‘construction’ of demand resources can also be terminated or even reversed easily and quickly, many stakeholders are often reluctant to include them in resource adequacy assessments. Finally, DSM resources, especially demand response may only be callable a limited number of times per season.

In the past, DSM resources in resource adequacy evaluations have usually been interruptible loads at a small number of large industries and amounted to only a few percent of total resources. Treatment was largely standardized as a reduction from total load to create firm load excluding the interruptible loads. Since the 1980’s, the number and type of DSM programs has been increasing. In the future DSM resources may be 10% or more of total resources.

One final issue with DSM resources is that some of their impacts may have naturally been included in the historical demand series. If these resources are to be modeled explicitly during the resource adequacy assessment, the load forecast (and presumably the base historical load series) must be adjusted (upward) to obtain load before demand-side resource implementation. If the load is not modified DSM resources are implicitly being assumed to be used at the same time and in the same pattern in the future as in the past and their impact may be modeled as growing at the same rate load growth. Ideally, DSM resources are only used when economic or necessary to avoid an LOL Occurrence. Their use does not always occur at the same time year to year, it usually occurs when load is highest but may be used at other times, and its impact will depend on time of use.26

Table 1 summarizes a number of ways to include DSM resources in resource adequacy evaluations -- each with an explanation of the advantages and disadvantages. It is appropriate to use more than one method of modeling DSM resources within the same analysis. Within one analysis, conservation programs may be intrinsic to the load forecast; the impact of residential time-of-use rates may be used to explicitly alter load; interruptible customers may be treated as an emergency operation procedure; air conditioner cycling may be explicitly modeled on an hourly basis; and public appeals may be ignored as their use is considered a loss of firm load.

26 The RIS survey responses did not identify any consist or typical treatment of DSM resources.
<table>
<thead>
<tr>
<th>Treatment</th>
<th>Examples</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm Load</td>
<td>Voltage reductions or public appeals not considered in resource adequacy analysis.</td>
<td>Load must be adjusted by adding back in the affects of these actions.</td>
</tr>
<tr>
<td>Load Forecast Modification - Implicit</td>
<td>DSM resources dispatched locally (by customer or distribution utility). Allow DSM resources to remain in historic load series and do not model in load forecasting.</td>
<td>Firm load is understated. Affects of demand resource use should be added back in. Information required for adjusting load is often not available.</td>
</tr>
<tr>
<td>Load Forecast Modification - Explicit</td>
<td>Any DSM resource may be modeled this way. Often the best treatment for non-dispatchable demand resources.</td>
<td>Parameters necessary for adjusting load are readily available. In margin ratios, DSM resources may be used to reduce reported firm load or added to resources. No standard treatment is currently defined. Usually use derated or effective capacity of demand resource.</td>
</tr>
<tr>
<td>Resource - EOP</td>
<td>Voltage reductions, public appeals and interruptible load often modeled as emergency operating procedures (EOP).</td>
<td>EOPs are often not included either as a load reduction or as a resource in margin calculations. This makes comparison of margins between jurisdictions difficult.</td>
</tr>
<tr>
<td>Dispatchable Resource</td>
<td>Dispatchable (often industrial) load.</td>
<td>In margin ratios, demand resources may be used to reduce reported firm load or added to resources. No standard treatment is currently defined. Either installed capacity or effective capacity may be used in ratios hampering comparison across areas.</td>
</tr>
<tr>
<td>Dispatchable Resource with Limitations</td>
<td>Interruptible load may have a maximum number of times it may be called upon in a period of time. Permits modeling of such things as loss of diversity from air conditioning control.</td>
<td>Usually but not always coincides with including demand resource on resource side of ratio. Characteristics related to usage limitations are cannot be reported in simple reserve or capacity margin ratios. Calculation of effective capacity is not always obvious—for example effective capacity of air conditioner control depends on duration of peak.</td>
</tr>
</tbody>
</table>
How Demand Side Management Data is Developed

As the industry’s use of Demand-Side Management evolves, NERC’s data collection and reliability assessment need to change highlighting programs and demand-side service offerings that have an impact on bulk system reliability.

NERC’s seasonal and long-term reliability assessments currently assume projected EE programs are included in the Total Internal Demand forecasts, including adjustments for utility indirect demand response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Demand Side Management involves all activities or programs undertaken to influence the amount and timing of electricity use (See Figure 6).

Figure 6: Demand-Side Management and NERC’s Data Collection

Note the context of the definitions is demand-side management, rather than bulk power systems and, therefore, they are not meant to mirror those used in the system context. The demand response categories are defined below support Figure 6.

Energy Efficiency: permanent changes to electricity use through replacement with more efficient end-use devices or more effective operation of existing devices. Generally it results in reduced consumption across all hours rather than event-driven targeted load reductions.

Demand Response: changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Dispatchable: demand-side resource curtails according to instruction from a control center.
**Controllable**: dispatchable demand response, demand-side resources used to supplement generation resources resolving system and/or local capacity constraints

**Capacity**: demand-side resource displaces or augments generation for planning and/or operating resource adequacy; penalties are assessed for nonperformance

**Direct Control Load Management**: demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

**Contractually Interruptible (Curtailable)**: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council’s seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

**Critical Peak Pricing (CPP) with Control**: demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

**Load as a Capacity Resource**: demand-side resources that commit to pre-specified load reductions when system contingencies arise

**Ancillary**: demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for nonperformance

**Non-Spin Reserves**: demand-side resource not connected to the system but capable of serving demand within a specified time

**Spinning/Responsive Reserves**: demand-side resources that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event.

**Regulation**: demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin

**Energy-Voluntary**: demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but nonperformance is not penalized

**Emergency**: demand-side resource curtails during system and/or local capacity constraints

**Economic**: Demand-side resource that is dispatched based on an economic decision

**Energy-Price**: Demand-side resource that reduces energy for incentives

**Demand Bidding & Buyback**: demand-side resource that enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high.

**Non-dispatchable**: demand-side resource curtails according to tariff structure, not instruction from a control center

**Time-Sensitive Pricing**: retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost and/or peak periods
Time-of-Use (TOU): rate and/or price structures with different unit prices for use during different blocks of time

Critical Peak Pricing (CPP): rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours

Real Time Pricing (RTP): rate and price structure in which the price for electricity typically fluctuates to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis

System Peak Response Transmission Tariff: rate and/or price structure in which interval metered customers reduce load during coincident peaks as a way of reducing transmission charges

Assessing Demand Response Performance

In order for NERC to understand the benefits of demand response and its impact on reliability, NERC must measure how well it performs and develop industry confidence. The electric industry is increasingly deploying demand response programs as a way to maintain bulk power system reliability. For NERC to provide a comprehensive reliability assessment on demand response resources, historical metrics are needed to assess the performance of these resources. Similar to the characteristics of renewable resources, demand response resources are variable, susceptible to ramping, and are not always controllable by the system operator. An expectation of non-performance is needed to accurately plan and operate a system that incorporates large amounts of demand response resources.

Currently, NERC requests data, as part of the Seasonal and LTRA data collection, for on peak projections and actual performance of demand response used for capacity that is dispatchable and controllable, aggregated by Region/Subregion. This allows Total Internal Demand projections to be reduced by the amount of demand response expected on peak (Net Internal Demand). When calculating reserve margins to determine resource adequacy, Net Internal Demand is included. However, to evaluate the performance of demand response at a programmatic level, more detailed data is needed to address demand response availability. This includes, but not limited to, tracking individual demand response programs, calculating realization rates, and average event durations.

To assess performance quantitatively, a reference case or “Baseline” is needed as a basis for measurement. A Baseline is an estimate of the electricity that would have been consumed by a Demand Resource in the absence of a Demand Response Event. The Baseline is compared to the actual metered electricity consumption during a Demand Response event to determine a realized demand reduction. Depending on the type of Demand Response product or service, Baseline calculations may be performed in real-time or after-the-fact. The system operator may offer multiple Baseline models and may assign a Demand Resource to a model based on the characteristics of the Demand Resource’s Load or allow the Demand Resource to choose a performance evaluation model consistent with its load characteristics from a predefined list. Figure 7 illustrates the concept of Baseline relative to a Demand Response Event using simulated
data^{27}. Understanding past behavior of Demand Response programs is critical for projecting both dispatchable (event-driven) and non-dispatchable (price-driven) demand response towards planning (demand reduction) and operational reliability.

Figure 7: Concept of Baseline relative to a Demand Response Event

Incorporating Demand Response in a Reliability Assessment

Demand Response programs have been in use for many years, providing more direct control to system operators. In addition, high performance factors are emerging from demand response providers not using direct control methods. The influence of demand response on reliability concentrates on peak demand reduction, periods of high wholesale prices, or low-reserve conditions rather than on reductions in overall energy consumption.

Long-term reliability benefits include reduced supply-side and transmission requirements at time of peak or other times when resource availability is reduced. Additionally, demand response supports the management of operational reserves/flexibility as well as long-term planning reserves.

All demand response resources may benefit overall system reliability, though some demand response options benefit system reliability more than others. The most dependable demand response resources are dispatchable provided by load resources under contractual obligation to perform, subject to dispatch by grid operators, and required to meet measurement & verification standards consistent with their importance to grid reliability.

Some demand response options can have more reliability benefits than conventional supply-side peaking resources. The reliability benefits of demand response are a function of, among other things, any limits on annual interruptions, the frequency of interruptions, the duration of interruptions, the ramp-up time to reduce load, and penalties or sanctions for non-performance.

^{27} Demand Response Measurement & Verification standards are being developed by the NAESB DSM-EE Subcommittee which include baseline calculations methodologies used for evaluating performance. Information on the status of this group’s effort is available at:  [http://www.naesb.org/dsm-ee.asp](http://www.naesb.org/dsm-ee.asp).
Incorporating Energy Efficiency in a Reliability Assessment

The benefits and characteristics of EE have been well studied and documented. In addition to energy savings, EE may reduce peak demand and defer the need for new investments.

There are a variety of ways for energy efficiency to be measured. The most straightforward method is to use the expected, or average, impact. In some cases, a more conservative measure may be used de-rating energy efficiency impacts for uncertainty in load reduction (the “dependable” reductions). Successful integration of energy efficiency into resource planning requires close coordination between those responsible for energy efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives.

NERC currently obtains forecast internal demand data for summer/winter peaks. Determining the effects of energy efficiency on peak internal demand can provide a measure of reliability benefits.

Different energy efficiency programs (industrial, commercial and residential) may influence on total capacity (MW) reduction depending on the time of day reduction is desired. Load forecasting is a critical component to understand the overall peak reduction observed or expected. Tracking and validating energy efficiency programs is vital to increase the accuracy of forecasts.

How to Incorporate Energy Efficiency

To incorporate energy efficiency into resource planning, the energy efficiency peak demand reduction must be defined so resource planners can evaluate it along with capacity resources. Care must be exercised, to assure that the estimates are not misused for other applications. For example, a peak value may be developed for a transmission study based on the energy efficiency reduction during the 12 monthly peaks, but then misused in a generation planning application with a single annual peak.

Analysts can use the same engineering or statistical models developed for producing energy reduction estimates (assuming that the model has sufficient hourly information to match the peak definitions). It is incorrect to assume the largest demand reduction from an energy efficiency measure occurs during peak demand. The coincident peak reduction is generally lower than the non-coincident peak reduction:

1. The timing of the largest reduction does not match the timing of the utility peak,
2. Not all measures will be operating at the time of the peak (people are not home), and
3. Equipment not installed or maintained properly.

In addition, there are synergistic affects that can increase or decrease the reductions depending upon other energy efficiency measures.

Percentage energy savings is not the same as percentage demand savings. For example, in California, SEER was used as the primary measure of AC unit efficiency. Codes and standards were written to promote high SEER units in the state, with the untested expectation that the more efficient unit would also help reduce capacity needs. Many manufacturers responded to the SEER metric with high SEER units that had two compressors and may result in a higher peak demand.

Guidelines for Demand Modeling in a Reliability Assessment

The Reliability Assessment should describe load uncertainty modeling, demand forecasts and demand-side resources. In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

a) Discuss the difference between the coincident and non-coincident peak. Review the methods used to develop both peak conditions.

b) Compare last year’s 2008–2017 average annual growth rate versus this year’s 2009–2018 average annual growth rate for your 50/50 forecast, and present the key factors leading to any significant changes in the forecast.

c) Discuss weather and economic assumptions upon which the 2009 – 2018 50/50 demand forecast is based.

d) Describe the regional or subregional quantitative analyses assessing the variability in projected demand due to weather, the economy, or other factors.

e) Summarize the uncertainty modeling used and how demand forecasts are developed for off-peak as well as on-peak conditions.

f) What method is used to aggregate total internal peak demands of individual member’s actual loads for use in the forecast? Separately:
   i. Specify and describe the current and projected energy efficiency programs
   ii. Specify and describe the current and projected demand response programs that reduce peak demand — i.e. interruptible demand; direct control load management; critical peak pricing with control; load as a capacity resource, etc.
Chapter 4—Supply & Transactions

Generation resource information is a critical component of reliability assessments because it allows NERC and others to assess whether or not reporting entities have or project enough generation resources to be able to serve load. Generation resources can be of many forms including, but not limited to, nuclear, fossil, solar, wind, and hydro. Some entities also consider certain DSM programs as generation resources.

How Regional Entities Identify Resources

Several NERC Regions consist of entities with FERC approved organized markets and traditional markets. However, others do not operate markets. The entities within these different markets treat generation resource/capacity differently as it relates to reliability assessments and reserve margin calculations. For example, as it relates to resources:

- ERCOT may consider all existing and operable resources to be available to serve the market and include them in margin calculations. Any undeliverable capacity due to transmission constraints is managed through congestion management.
- PJM includes all capacity resources in the reserve margin calculations. All other existing resources are not included in the margin calculations.
- In non-market areas the concept of “native load” still typically prevails with sometimes extensive use of bilateral contracts for assuring supply for non-generating utilities.

As such, there is a considerable amount of on-the-ground generation that may not be accounted for in any calculations reported by certain regions. This issue becomes even more complex for long-term reserve margin assessments because of the uncertainty involved in what generation gets built and how each region accounts for future resources.

Recognizing these differences between various market structures for the reporting entities, NERC has developed various definitions and categories of generation resources, purchases, and sales that provides for granularity needed to perform computation of generation resource metrics to understand reliability trends for various NERC Regions. Future reliability assessments may require additional transparency and granularity as it relates to generation resource/capacity to assess short-term and long-term reliability.

How NERC Categorizes Capacity

All existing and future (including conceptual) resources must be reported in one of the following categories. Resources may not be double counted across categories. It is up to the reporting entity as to which category resources are reported. Best judgment should be exercised in the determination of which category to report resources.

Resources that are contained within the region’s and/or subregion’s physical or electrical boundary must be reported by that region and/or subregion. Resources that are located outside of
a certain reporting region’s and/or subregion’s physical footprint but are electrically connected only to that reporting region’s and/or subregion’s system should be reported by that region and/or subregion. The output of resources that cross boundaries to serve load should be reported as a purchase or sale.

It is important to note that capacity is categorized here, and not individual generators. An individual generator’s installed/nameplate capacity may be incorporated in more than one category (i.e. Of the 5 MW of installed/nameplate Existing Wind Turbine Generator, 1 MW categorized as I.A – Existing, Certain; 4 MW categorized as I.B. – Existing, Other.)

I. Existing Generation Resources

I.A. – Existing, Certain — Existing generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

- Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
- Where organized markets exist, designated market resource\(^\text{29}\) that is eligible to bid into a market or has been designated as a firm network resource.
- Network Resource\(^\text{30}\), as that term is used for FERC pro forma or other regulatory approved tariffs.
- Energy-only resources\(^\text{31}\) confirmed able to serve load during the period of analysis in the assessment and will not be curtailed\(^\text{32}\)
- Capacity resources that can not be sold elsewhere
- Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed\(^\text{33}\) during the period of analysis in the assessment

I.B. – Existing, Other — Existing generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in I.A. This category includes, but is not limited to the following:

- A resource with non-firm or other similar transmission arrangements

\(^{29}\) Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\(^{30}\) Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\(^{31}\) Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129). Note: Other than wind and solar energy, WECC generally does not have energy-only resources that are counted towards capacity.

\(^{32}\) Energy only resources with transmission service constraints are to be considered in category I.B

\(^{33}\) Energy only resources with transmission service constraints are to be considered in category I.B
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason
- Mothballed generation (that may be returned to service for the period of the assessment)
- Portions of variable generation not counted in the I.A. category (e.g. wind, solar, etc. that may not be available or de-rated during the assessment period)
- Hydro generation not counted as I.A. or de-rated
- Generation resources constrained for other reasons

I.C. – Existing, but Inoperable — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero (0). This includes all existing generation not included in categories I.A. or I.B., but is not limited to, the following:
- Mothballed generation (that can not be returned to service for the period of the assessment)
- Other existing but out-of-service generation (that can not be returned to service for the period of the assessment)
- This category does not include behind-the-meter generation or non-connected emergency generators that normally do not run.
- This category does not include partially dismantled units that are not forecasted to return to service

All existing generation resources must be counted in I.A., I.B. or I.C. and should not be double counted between these three categories. Where categorization as to the I.A. or I.B. category is not clear, the generation should be designated as I.B.

II. – Future Generation Resources

This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:
- Construction has started
- Regulatory permits being approved, any one of the following:
  - Site permit
  - Construction permit
  - Environmental permit
- Regulatory approval has been received to be in the rate base
- Approved power purchase agreement.
- Approved and/or designated as a resource by a market operator
II.A. – Future, Planned — Generation resources anticipated to be available to operate and deliver power within or into the region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

- Contracted (or firm) or other similar resource
- Where organized markets exist, designated market resource\(^{34}\) that is eligible to bid into a market or has been designated as a firm network resource.
- Network Resource\(^{35}\), as that term is used for FERC \textit{pro forma} or other regulatory approved tariffs.
- Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed\(^{36}\)
- Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve

II.B. – Future, Other – this category includes future generating resources that do not qualify in II.A. and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:

- Be curtailed or interrupted at any time for any reason
- Energy-only resources that may not be able to serve load during the period of analysis in the assessment
- Variable generation not counted in the II.A. category or may not be available or is de-rated during the assessment period
- Hydro generation not counted in category II.A. or de-rated

Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

III. – Conceptual Generation Resources

Conceptual — This category includes generation resources that are not in a prior listed category, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study
- “Place-holder” generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

\(^{34}\)Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\(^{35}\)Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\(^{36}\)Energy only resources with transmission service constraints are to be considered in category II.B
How NERC Categorizes Transactions

Contracts for Capacity

Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one region and sold to another region, the region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside region. The purchasing region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

The following examples are provided to show how transactions are handled between two reporting regions for Purchases/Imports and Sales/Exports:

1. Unit physically located in Area A that is fully owned by a company in Area B and not connected to the Area A network but instead has a direct and adequate transmission connect to the Area A.

   Solution: Show the unit completely in Area B with no transfers. All derating accounted for in Region or Province B.

2. Unit physically located in Area A that is half owned by a company in Area B.

   Solution: Show the unit completely in Area A with a sale to Area B of half of the capacity. Area B would show a purchase of half of the capacity from Area A, as long as Area B can demonstrate adequate transmission capacity. Identify the sale/purchase as unit specific. Derating accounted for in Area A and sale reduced by 50% (depends on contract) amount.

3. Unit physically located in Area A that is fully owned by a company in Area B.

   Solution: Show the unit completely in Area A with a sale to Area B of the full amount. Area B would show a purchase of the full amount of capacity from Area A, as long as Area B can demonstrate adequate transmission capacity. Identify the sale/purchase as unit specific. The derating due to transmission should be accounted for in Area A and the sale reduced by derated amount in Area B.

The following are categories of Purchases/Imports and Sales/Exports contracts:

I. Firm

   (1) Firm implies a contract has been signed and may be recallable.

   (2) Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriate report the generating capacity that is subject to such Firm contract.

II. Non-Firm

   (1) Non-Firm implies a non-firm contract has been signed.
(2) Non-Firm Purchases and Sales should not be considered in the reliability assessments.

III. Expected

(1) Expected implies that a contract has not been executed, but in negotiation, projected or other. The Purchases or Sales are expected to be firm.

(2) Expected Purchases and Sales should be considered in the reliability assessments.

IV. Provisional

(1) Provisional implies that the transactions are under study, but negotiations have not begun. These Purchases and Sales are expected to be provisionally firm.

(2) Provisional Purchases and Sales should be considered in the reliability assessments.

The above transaction categories can be further broken down to obtain more granular data. The following are not exclusive, but may represent a majority of capacity backed transactions represented in the transaction definitions.

Full-Responsibility Purchases
Total of all purchases for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers. Each purchaser and seller must agree on which of their transactions are reported under this heading.

Owned Capacity/Entitlement Located Outside the Region/Subregion
The amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion.

Guidelines for Supply & Transactions

The Reliability Assessment should describe significant issues regarding the supply and transactions. In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

a) Identify the amount (Certain and Other) of Existing, Future, and Conceptual capacity resources in-service or expected to be in-service during the study period.
   i) Identify the portions (MW) that are variable (i.e. wind, solar, etc.) expected on peak and maximum capacity from the variable plants.
   ii) Identify the portions (MW) that are biomass (wood, wood waste, municipal solid waste, landfill gas, ethanol, and other biomass).37

b) For Future and Conceptual resources, what is process used to select resources for reliability analysis/capacity margin calculations (i.e. forward capacity markets,

37 Defined by EIA as: “organic nonfossil material of biological origin constituting a renewable energy source.”
c) Imports on Peak

i) Identify and quantify any imports from other regions and also those imports between sub-regions that affect sub-regional capacity margins. Categorize them as:

   i. Firm — contract signed.
   ii. Expected — no contract executed, but in negotiation, projected, or other.
   iii. Provisional — transactions under study, but negotiations have not begun.

   ii) What portion of the imports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if import assumptions are based on partial path reservations.

d) Exports on Peak

i) Identify and quantify any exports to other regions and also those exports between sub-regions that affect subregional capacity margins. Categorize them as:

   iv. Firm — contract signed.
   v. Expected — no contract executed, but in negotiation, projected, or other.
   vi. Provisional — transactions under study, but negotiations have not begun.

   ii) What portion of the exports is backed by firm contracts for both generation (contract tied to specific generator) and transmission? Clarify if export assumptions are based on partial path reservations.

e) Identify the projected capacity margins and compare them to the regional, subregional, state, or provincial requirements.

   i) If applicable, what are the assumptions that were used to establish the regional/subregional capacity margin criteria or target margin level?
   ii) What is the amount of resources internal and external to the region or subregion that are relied on to meet the target margin level, or forecast load for the assessment period?\[38\]
   iii) Describe any reliance of the region or subregions on emergency imports, reserve sharing or outside assistance/external resources (clarify whether it is external to the subregion or the region) and where these resources are expected to come from.
   iv) Describe the latest resource adequacy studies (i.e. Loss-of-Load Expectation, Expected Unserved Energy, etc.).
   v) What is the difference in how the region treats short-term (i.e. 1-5 years) and long-term (i.e. 6-10) capacity margins requirements?

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38 Each region/subregion may have their own specific margin level (or method) based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the regional/subregional Target Capacity Margin level is adopted as the NERC Reference Margin Level. If not, NERC assigned 13 percent capacity margin for predominately thermal systems and 9 percent for predominately hydro systems.
vi) Discuss any significant changes from last year’s assessment, including major new capacity that is projected to come into service.

vii) Discuss resource adequacy if resource unavailability is higher than expected due to fuel interruptions or other conditions such as extended drought or forced outages.

viii) Discuss operational measures available if peak demands are higher than expected due to weather or other conditions. For this analysis, use 90/10 forecast demands where available, an approximation of them if 90/10 forecasts are not available or an extreme, historical weather condition.

ix) Describe how energy-only, Existing Other wind and transmission-limited resources are considered in your resource adequacy assessment.

x) Summarize any additions of large amounts of variable resource and energy/risk assessment of resources along with the planning and operational considerations and your assessment of impacts on reliability.

f) Identify unit retirements which have significant impact on reliability. What measures have you taken to mitigate the reliability concern?

g) Describe the latest generation deliverability (both internal and external) studies performed.

i) Explain and/or reference documentation, and provide the definition of deliverability used in your region/subregion. If there is none, explain what is done to ensure that the resources are sufficient and deliverable to meet your load requirements at the time of system peak.

ii) If any deliverability concerns are identified, explain what mitigation procedures are in place to address them.

iii) What analysis is done to ensure that external resources needed are available and deliverable on peak?

iv) What major transmission additions are required to support the addition of new resources or imports, especially in the 6–10 year time period? Emphasize transmission elements that have a long lead time.

Reporting Supply & Transaction Data

All supply data is submitted on the LTRA data collection form on Schedules 3A(Summer Peak) and 3B(Winter Peak) and supports the Form EIA-411 submission. All installed capacity should be reported in one of the six capacity categories, as defined in this Guidebook.

Total imports and exports are also reported on these schedules. To validate this data, NERC collects disaggregated transaction data on Schedules 4A-4D. Regional coordination is needed to reconcile transaction values reported on these forms. For example, if ERCOT is counting on a 200 MW firm transaction import from WECC, WECC should report a 200 MW firm transaction export.
Chapter 5—Resource Adequacy Assessment

A discussion of the approaches to resource adequacy assessment of the eight Regional Entities is a challenge in semantics. The review that follows attempts to go behind the specific terms used in the Regions to capture the intent and practice, rather than exclusive methods and processes. Furthermore, distinction must be made between assessing resource adequacy (as done by the Regional Entities and NERC) as compared with the assumptions, models and methodologies used by entities responsible for determining (i.e. setting) resource adequacy requirements for their respective jurisdictions. The two activities are distinctly different in nature, although they may share some commonality (for instance, regarding the analytic tools used). The choice of words was intentionally made to convey a broader connotation so that practices similar in intent would not appear different, as might be the result of using the precise terminology of each Region. The Regional Entities have developed the foundation and support for resource adequacy assessment practices, and as such, this Guidebook articulates the corresponding foundation, support and recommendations for a NERC independent review.

Conducting assessments of the adequacy of resources on a regional basis requires a great deal of coordination with member organizations to ensure compatibility and comparability of the data supplied. Data must be organized in such a fashion that it is consistent and shareable.

Full standardization of assessment methods and criteria between Regions, even if desirable, may be difficult to attain due to both the need to reflect regional characteristics and the considerable investment in time and effort which the Regions have made. The most important consideration is the resultant reliability the the customer sees over time which verifies the soundness of the data and the methods used in assessment practices.

Resource Adequacy Assessment is over the long-term. There are three basic areas in which consistency of data and methods are appropriate within a Region:

1) Demand Characteristics
2) Capacity Characteristics
3) Regional Resource Assessment Procedures

Demand Characteristics

To the extent that resource adequacy assessments are based on an analysis of combined demand and capacity, most Regions make some effort to assure that the demand forecasts of their systems are consistent. This effort often takes the form of general encouragement to furnish demand projections for “normal” weather for the season in question. In Regions in which individual systems make and report their own assessments to the Region, a similar effort is made.

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39 Comprehensive resource adequacy assessments are also performed at the Regional Level. For example, NPCC’s Subregional assessments are posted at: http://www.npcc.org/documents/reviews/Resource.aspx
Most Regions which combine the demands of member systems make use of the regional experience as to diversity in those peak demands. The experience of some Regions supports the projection of diversity and in others it does not.

All Regions include an assessment of the effect of deviation of demands from forecast as part of their procedures. Many include an analysis of low probability, high load scenarios or some type of extreme contingency event that may include extreme weather conditions. NERC’s LFWG performs a bandwidth analysis on load forecasts to model variability, as mentioned in the Demand and Load Forecasting chapter of this Guidebook.

**Capacity Characteristics**

The three essential characteristics of generating capacity are the full-output rating of an individual unit (installed or nameplate value), the expected on-peak capacity values (and associated deratings), and the availability rates of those units. All Regions have a formal requirement for establishing the rating of generating capacity based on actual test and/or operating data.

All Regions, at one level or another, use either a probabilistic or an engineering judgemental evaluation of the effects on adequacy of the operational variability rates of capacity. In general, the projections of availability used in assessments are based on industry-wide, regional, or specific unit historical performance data. The NERC Generator Availability Data System (GADS)\(^{40}\) collects this unit specific performance data on a voluntary basis. This unique series of databases is used to collect, record, and retrieve operating information for improving the performance of electric generating equipment. It also provides assistance to those researching the vast amounts of information on power plant availability stored in its database. The information is used to support equipment reliability and availability analyses and decision-making by GADS data users.

**Regional Resource Assessment Procedures**

These guidelines provide an overview of the approaches to the assessment of resources adequacy in two parts:

- **General Procedures for the Assessment of Adequacy**
  - Identification of specific criteria levels, if any;
  - Nature of data assessed at the regional level

- **Specific Procedures for the Assessment of Adequacy**
  - Detail on various evaluation methods
  - Identifying specific parameters that are entered into evaluations
  - Standards or standard practices enforced within the Region

All Regional Entities provide for the periodic long-range assessment of the adequacy of resources within their respective Regions. There are differences in overall approach among

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the regions which stem from the inherent structural and geographic differences in the relationships between Regional Entities and their member systems.

A comprehensive assessment of adequacy requires more than a single measure and an understanding of the effects of variation in important parameters is vital. These include, but are not limited to:

- Rate of demand growth
- Load shapes
- Sensitivity of demands to weather
- Sensitivity of demands to economic conditions
- Assistance from neighboring systems
- Delays to in-service dates
- Fuel and unit availability
- Other emerging or industry issues that may impact reliability

A probabilistic approach to generation adequacy analysis is used at some level in nearly all Regions, either by making direct probabilistic assessments or by identifying an equivalent percent reserve margin. In using probability methods, results are influenced by the specific parameters considered as well as by the handling of these parameters. A definitive comparison of end results requires an understanding of these variations.

A survey of Resource Adequacy Assessment practices conducted by NERC’s Resources Issues Subcommittee (RIS) provides insights into common practices and objectives of resource adequacy assessments as well as regional differences. Approximately 60% of the survey recipients responded including all eight of NERC’s regional entities, 57% of NERC’s planning coordinators and three entities that are not NERC-registered Planning Coordinators. Reference is also made to documents, which explain the resource adequacy assessment methods of ISO New England (ISO-NE), ERCOT, the Midwest Planning Reserve Sharing Group (Midwest PRSG) and the Northwest Power and Conservation Council (NWPCC).

In reviewing the survey responses (See Appendix II, Table A & B) there is sufficient commonality in certain elements of resource adequacy assessments to be viewed as expectations:

- **Assessment against specified Level of Reliability:** Resource adequacy assessments are intended to evaluate whether there are sufficient supply-side and demand-side resources to meet the aggregate electrical demand and energy requirements (including losses) of every end-use customer, who is not subject to voluntary curtailments through a demand reduction program, with a specified degree of reliability.

  o Specified level of reliability is typically expressed as the “loss of load expectation” (LOLE) of disconnecting any firm load due to resource deficiencies. Compliance with this criteria shall be evaluated probabilistically, such that the LOLE of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over
interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.”

- Although resource adequacy requirements are almost always expressed in terms of planning reserve margins, or capacity margins (for the sake of simplicity, these will collectively be referred to as reserve margins); the numerical targets are typically derived from some type of probabilistic assessment. Even where a deterministic analysis is the basis for reserve margin targets, an effort is made to assess the various factors that pose a risk to the adequacy of resources comprising the bulk power system and provide coverage for these risks through reserve margin components.

- The objective of the assessment is to show how well-protected a system is from disconnecting firm load. Furthermore, it demonstrates compliance with the Regional criteria.

- For regions where intermittent resources are prevalent and the maximum output is not reasonably assured at times when the resources are needed, these resources are typically derated so that the reserve margin remains a useful metric.

**Assessment is over Long-term Timeframe:** The timeframe of the assessments is generally from 1 or 2 to 10 years out to allow for timely notice of any impending generation insufficiencies to the targeted audience of the assessment, i.e. the market or utilities’ state regulators, in order to allow sufficient time to implement resource adequacy measures to avoid such insufficiencies.

**Issues & Considerations in Resource Assessment**

There are several areas that Regional Entities must consider when conducting a resource assessment, such as resource adequacy analysis, demand modeling, demand-side management, etc. This section summarizes many of these areas, while the Demand and Load Forecasting chapter covers specific about demand.

**a) Resource Adequacy Analysis**

The survey results indicate that six of the eight regional entities and the vast majority of the planning coordinators use some type of probabilistic assessment method to perform their resource adequacy analyses. SERC, a region currently without a region-wide resource adequacy assessment method, has formed a reliability assessment working group, which will make recommendations regarding how to proceed. Within SERC may of the utilities have their own methodologies, most of which are probabilistic (LOLE/LOLP based). WECC, a region currently using a deterministic resource adequacy assessment method, has initiated a pilot project to determine if a probabilistic assessment is workable for that region.

These probabilistic analyses generally fall into two categories: Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE). Regional differences in

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resource mixes (abundance of energy-limited resources and/or well-developed demand response programs), the geographical location of resources on the transmission grid, access to out-of-area reliability resources (i.e. tie benefits) and/or market or regulatory approaches to implementing resource adequacy may all affect the assessment methods and assumptions. An overview of the differences and similarities in resources adequacy analysis methods can be found in Appendix I.

b) Treatment of Fuel-limited Resources (hydro, wind, etc.)

State policies such as Renewable Portfolio Standards (RPS) and those favoring a carbon-constrained future are big drivers to the construction of renewables, some of which are highly variable and not dispatchable (e.g. wind and solar PV). Hydro is a traditional fuel-constrained technology that has varying amounts of dispatchable flexibility. Finally, some thermal units can become energy-constrained due to air quality and other environmental limitations.

The traditional approach in a capacity adequacy assessment has been to derate energy-limited resources. However, this approach does not fully capture that some resources such as wind are considerably more constrained than other resources such as hydro. One method to derate wind is to consider its firm load carrying capability. Another approach has been to evaluate wind’s contribution to capacity adequacy when it is needed most, i.e. during cold snap or heat wave events. The motivation for derating resources is to view them in a more comparable manner with other more traditional resources so the familiar comparative metrics such as percent reserve margins / percent capacity margins remain meaningful. For example, if wind were included without derating capacity (as are virtually all other resources) then minimum reserve margins of 90 percent could be reasonable for large penetrations. In such a situation the addition of more wind resources would, most likely, simply increase the minimum reserve margin, with only minor improvements in avoiding additional LOL occurrences.

It is possible to model wind, hydro and other energy-constrained resources as stochastic parameters. This approach certainly identifies the attributes of energy-constrained resources better than the derating approach discussed above. When performing this type of a study, it is important to keep partial correlations intact. For example, load and wind may be unrelated except that during periods of severe heat or cold, wind may be partially correlated in a negative manner to load. The problem with treating intermittent resources as stochastic parameters is that the percent reserve margin metric is not comparable to metrics for other areas.

c) Addressing Resource Deliverability

Resource deliverability can have different meanings as defined by NERC. The recent RIS survey also gathered information about how regional entities and planning coordinators define the term “deliverability”. Based on the results of the survey, approximately 90% of the entities that responded do not have an official definition of “deliverability” with regards to generation resources.

The survey also requested the entities to explain what is done to ensure that the generation resources are deliverable to meet the load requirements at the time of
system peak. The responses varied significantly from entity to entity. However, approximately 97% of the entities who responded perform some type of transmission assessment including regional studies, transmission provider studies and interconnection study processes governed by each transmission provider’s OATT. Table 2 is a summary of the results of the survey:

<table>
<thead>
<tr>
<th>Description of Test</th>
<th>Response (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection process—all resources are deliverable</td>
<td>39</td>
</tr>
<tr>
<td>Transmission provider studies</td>
<td>29</td>
</tr>
<tr>
<td>Regional transmission studies</td>
<td>29</td>
</tr>
<tr>
<td>Other</td>
<td>3</td>
</tr>
</tbody>
</table>

An outstanding issue in many adequacy assessments is that the studies performed to interconnect resources do not examine the simultaneous transfer capability of new and future resources. Thus resource deliverability is not assured. These issues are further discussed under the last section of the Transmission Reliability Assessment Chapter of this Guidebook.

d) Reserve Margin Analysis

Once the probabilistic adequacy assessments are completed, they are typically translated into a planning reserve margin for a system. Starting with an assessment that exactly satisfies the specified target, (e.g. 1 day in 10 years LOLE), the common method of calculating reserve margin is represented by the following equation:

\[
RM = \frac{[(\text{Resources} + \text{Net Transactions}) - (\text{Net Internal Demand})]}{(\text{Net Internal Demand})}
\]

The reserve margin is a measure of available capacity over and above the capacity needed to meet normal peak demand levels. Planning reserve capacity is needed to provide an operator with flexibility in case resources are unexpectedly unavailable during the time of peak demand or when demand exceeds the forecast.

Regions and subregions may vary this formula to reflect certainty of demand-side management resources. Most regions and subregions use planning reserve margin as their reliability metric. NERC assessments use the reserve margin metric, which is described in the next section.42

An important issue in preparing reserve margin analyses is how to count resources and how to depict load. Transparency is needed to address all components of these metrics. How much of wind capacity should be counted in the calculation? How are mothballed units counted in the calculation of reserve margin? What is considered the

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42 In 2008, NERC’s Planning Committee (PC) approved the use of the reserve margin metric in the NERC Reliability Assessments for 2009 and on, from a recommendation by the Reliability Assessment Subcommittee (RAS). The reserve margin normalizes the MW margin (Resources-Net Internal Demand) by Net Internal Demand). In prior years, NERC Reliability Assessments used the capacity margin metric, which normalized the MW margin (Resources-Net Internal Demand) by Resources.
peak load hour? How are imports (market), or tie benefits counted? Following are typical ways of treating loads and resources:

**Net Internal Demand:** Net internal demand is made up of peak load, which is generally the 50/50 (expected peak) forecast of the area.

**Resources:** The maximum capacities (nameplate) of thermal and hydro stations are typically included in the calculation in some analyses where hydro has significant storage. In other analyses, hydro capacity is derated to that available under adverse or critical water conditions. Typically, wind capacity is counted at 5 to 20 percent based on the effective load carrying capability (ELCC) of wind capacity analysis, or an analysis of wind capability during high risk situations. For example, NWPC is currently counting wind at 5% of its installed capacity. Other analyses base wind’s contribution to capacity adequacy at that available historically. Interruptible loads and demand-side management programs are sometimes included as resources. Often interruptible loads are included as one of the Emergency Operating Procedures, which may be counted in resource adequacy assessments. Mothballed units that are not expected to come back on-line before the next peak load season are typically omitted from the reserve margin calculation.

**Net transactions:** Net transactions are comprised of imports into the area minus sales out of the area. Only known power purchase agreements with outside markets are considered as imports. Import capability is not counted as additional capacity, except for those analyses that include tie benefits in the reserve margin calculation.

In some cases, transmission transfer capability for tie benefits is secured through a Capacity Benefit Margin (CBM) reservation. It is not mandatory for transmission providers to maintain CBM. The NERC Standards Committee Ballot Pool recently approved the MOD-004-1 standard, which defines the “process through which a Load-Serving Entity within a Balancing Authority Area associated with the Transmission Service Provider, or the Resource Planner associated with that Balancing Authority Area, may ensure that its need for Transmission capacity to be set aside as CBM will be reviewed and accommodated by the Transmission Service Provider to the extent Transmission capacity is available.” PJM is one of the transmission providers to maintain CBM. In PJM, CBM, expressed in megawatts, is the amount of import capability that is reserved for the emergency import of power to help meet LSE load demands during peak conditions and is excluded from all other firm uses. A decrease in the CBM increases the reserve requirement. In PJM, the Capacity benefit of Ties (CBOT), is a measure of the value that neighboring region interface ties bring into the region of study. The CBOT is the difference between a reserve requirement with CBM – and a reserve requirement run with a zero (0) CBM. The value of CBM is directly used in the various transmission path calculations, OASIS postings, for Available Transfer Capability (ATC) thus reducing the Total Transfer Capability (TTC) on each path.
The categories of capacity described in the *Supply and Transactions* chapter of this Guidebook provide a comprehensive list for reporting the various types of existing, future, or conceptual generating capacities.

**How NERC Computes Reserve Margins**

NERC reserve margin calculations are made up of three major components:

- Capacity Resources
- Demand
- Transactions (Imports/Exports)

The foregoing categories of capacity provide a comprehensive list for reporting the various types of existing, future, or conceptual generating capacities. The following provides guidance on how these categories are used to compute regional and sub-regional capacity margins for reliability assessment purposes.

**Existing, Certain** – These resources are confirmed able to serve load during the period of the analysis in the assessments. One hundred percent (100%) of these resources are included in all margin calculations.

**Existing, Other** – These resources may or may not be able to serve load during the period of the analysis in the assessments. These resources are included in the Perspective, Adjusted Potential and Total Potential Resource Margins.

**Existing, but Inoperable** – These resources are not able to serve load during the period of analysis in the assessments. Zero percent (0%) of these resources are not included in any margin calculation.

**Future, Planned** – These resources are confirmed able to serve load during the period of the analysis in the assessments. One hundred percent (100%) of these resources are included in each margin calculation except “Existing Certain & Firm Transactions Margin”

**Future, Other** – These resources may or may not be able to serve load during the period of the analysis in the assessments. Each reporting region or sub-region should make a reasonable judgment of the ability of such resources to serve load. In addition, the regions or sub-regions may adjust the capacity in this category, using a confidence factor, to reflect uncertainties associated with being able to rely on such resources to serve load. The adjusted capacity is included in the “Adjusted Potential Resources” calculation and one hundred percent (100%) is included in the “Total Potential Resources” calculation.

**Conceptual** – These resources may or may not be able to serve load during the period of analysis in the assessments. Conceptual resources may be used by the NERC Regions in future years for planning purposes and for meeting local regulatory requirements. Resources in this category may be adjusted to reflect uncertainties associated with being able to rely on such resources to serve load. The adjusted capacity is included in the
“Adjusted Potential Resources” calculation and one hundred percent (100%) is included in the “Total Potential Resources” calculation.

Figure 8 shows how the categories of capacity are used to calculate capacity margins shown in the reliability assessments. NERC uses a layered approach to evaluate capacity contributing to reserve margin calculations with different levels of certainty associated for each layer. To assess resource adequacy, NERC generally compares the NERC Reference Margin Level to Deliverable and Prospective Resources Margin.

**Figure 8: Reserve Margin Calculation Based on 2009 Capacity Definitions**

Guidelines for Resource Deliverability

The Reliability Assessment should describe how generating resources are determined to be deliverable or have sufficient transmission capability to serve the load under forecasted peak demand conditions. For example, some entities may perform a generator deliverability test as well as a load deliverability test. In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

- Describe conditions under which transmission studies are performed to ensure resource deliverability (e.g., load conditions, resource maintenance, transmission maintenance, contingency events evaluated, power transfer conditions, worst case dispatch, etc).

- Describe the interconnection process as it relates to a specific resource and transmission capability. For example, describe the transmission studies
performed, if any, as part of the interconnection process using the guideline provided above. If this process is governed by the transmission provider’s Open Access Transmission Tariff, then briefly describe the process and elaborate on the deliverability portion if appropriate.

- For network resources explain how a resource attains this status. For example, explain how “network resource” status is determined (e.g., transmission studies, ATC, transmission rights, etc). If transmission rights can be purchased, then explain how are these transmission rights determined to be available and under what conditions (refer to the first bullet).
Perfect or even near perfect transmission reliability would cost an infinite amount of money. Imagine a remote customer that needs to be served 100 percent of the time. In other words, zero risk of loss of supply to this customer. Obviously, this would require building a transmission line to serve the load. This single line would obviously not be enough, no matter how solidly it was built, to ensure the customer is served 100 percent of the time. For example, what if that line is struck by lightning? The customer would not have service. Therefore, two transmission lines need to be built, at least doubling the cost. Having a second transmission line will not be sufficient either because what if one line is out on maintenance and the other is struck by lightning. Two transmission lines would not be enough and a third line would be needed tripling the cost, and so on. Even if we had 100 transmission lines serving a load, there is still a very small possibility (earthquake, hurricane) that all those lines could be taken out of service. The planner must make a decision on how many lines are enough. In other words, how much risk is acceptable versus the cost necessary to serve the demand to some industry accepted level of reliability. Of course the bulk electric power system is much more complicated than trying to serve one customer.

a) Overall Transmission Assessment statement
b) Transmission additions and backbone project description
c) Transfer capability results
d) Thermal Issues (Rating violations and mitigation plans, etc.)
e) Voltage Issues
   i) Transient Voltage dip
   ii) Dynamic Reactive Requirements
   iii) Under Voltage Load Shedding
   iv) Stability
f) Dynamic Stability Issues
   i) Transient Stability
   ii) Long-Term Stability (e.g., beyond 20 seconds after a transient event)
   iii) Small Signal Stability
g) Under Frequency Load Shedding
h) Short Circuit Levels
   i) Describe the results of the TPL studies
j) Address resource deliverability issue
Guidelines for Transmission Reliability Assessment

In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

a) Do you expect to install more Under Voltage Load-Shedding (UVLS) in your region/subregion? How much load (MW) is targeted by Under Voltage Load-Shedding (UVLS) to protect against bulk power system cascading events and how does this influence your reliability assessment?

b) Describe the region/subregion plans for catastrophic events: for example, the loss of a fleet of generators due to the loss of a major pipeline or other fuel disruption, or loss of a major import path.

c) Does the region/subregion have plans for dealing with a drought? If so, explain how you have included the reliability impacts in the next few years. What is the reduction in projected total capacity (Hydro, fossil, and nuclear). How the region/subregion intends to meet the capacity/reserve margin requirements.

d) Describe the TPL-001 — TPL-004 planning studies performed by your regional entity’s participants, what reliability issues were identified and what are the plans to address them.

i) Summarize any transient dynamics, voltage, and small signal stability studies performed. Are there any anticipated stability issues that could impact the reliability during the study period?

   i. Do you have criteria for minimum dynamic reactive requirements or margins in your region/subregion? If yes, state the criteria and explain how it is being applied to meet the peak conditions.

   ii. What, if any, are the transient voltage-dip criteria, practices, or guidelines on the regional/subregional bulk power system do you have and how it is being applied to meet the peak conditions?

ii) Describe any dynamic and static reactive power-limited areas on the bulk power system in your region/subregion and plans to mitigate them (See Appendix I for discussion on this analysis). Do you have criteria for voltage stability margin in your region/subregion? If yes, state the criteria and explain how it is being applied to meet the peak conditions.

e) What new technologies, systems, and/or tools do you expect to deploy improving bulk power system reliability?
Chapter 7—Operational Issues

[SECTION UNDER DEVELOPMENT – TO BE INCLUDED IN A LATER VERSION]

a) Environmental, regulatory or other restrictions

b) Major unit or facility (e.g. PAR) outages that affect operation of the bulk-power system, and/or temporary operating measures to mitigate concerns

c) Other issues, or operating conditions (e.g. higher than expected forced outage rate of units, etc.) and any mitigation procedures

Guidelines for Operational Issues

In order to ensure consistency throughout the Reliability Assessment document, the following guidelines are recommended when developing the self-assessment narratives:

a) Are there any anticipated unit outages, variable resources, transmission additions, and temporary operating measures that may impact reliability?

b) Are there either environmental or regulatory restrictions that could potentially impact reliability? If so, please explain, including the projected magnitude (in MW) of the restriction and its impact on operational margins.

c) Are there any operational changes due to integration of large amounts of variable generation?

d) Have you considered fuel supply vulnerability in your region/subregion? If so, are there any anticipated concerns. If not, explain why this is not a concern.

e) Are there either environmental or regulatory restrictions that could impact reliability? If so, explain, including the projected magnitude (in MW) of the restriction and its impact on operating margins.

f) Describe any anticipated unusual operating conditions that could impact reliability.
Chapter 8—Other Issues

Examples:

a) New or emerging issues, if any
b) Define or give examples of what is a significant issue
c) Special reliability assessments performed

Occasionally, the PC will request that RAS undertake special assignments to further PC objectives. Similarly, RAS may self-initiate special assessments of the reliability of a Region(s), Subregion, or portion of an Interconnection as conditions warrant. If the assignment is to perform a special assessment of another NERC Region or subregion, RAS will initiate such assignments by first making contact with the appropriate personnel in the Region. Regional representatives will be expected to provide access to documents, studies, and arrange for interviews as needed by RAS to carry out its assignment. Any problems with access to required information are to be discussed with the PC. The results of any special assignment will be presented to the Region for review and comment before approval or publication.

d) Examples:
   i) Aging Infrastructure
   ii) Drought/Flood Conditions
   iii) Equipment/construction/siting delays
   iv) Other issues of concern
Chapter 9—Scenario Assessment

Background

Each year, NERC’s staff and its technical committees prepare a 10-year Long-Term Reliability Assessment (LTRA). This preparation includes data concentrated on Summer and Winter peak internal demand and associated demand and supply capacity, along with separately written regional self-assessments. These assessments form the basis for the NERC reference case, for which detailed analysis and discussion follows. The reference case generally is based on the assumption that policy/regulations will be constant throughout the studied timeframe and a variety of economic growth, weather patterns and system equipment behaves at expected, usually based on historic performance trends.

Scenario analysis can indicate the relative sensitivity of the reference case to changes in pre-specified conditions and may provide some insight into risks to regional reliability. Based on feedback from FERC and industry, a deeper understanding is desired regarding the potential reliability implications of a focused spectrum of reference case sensitivities. Development of a small set of scenarios for comparison to the reference case is an extremely valuable way to better understand the robustness of the reference case and to study potential impacts of scenarios on reliability.

For the 2008 LTRA cycle, NERC will begin development of plans to address scenarios identified in the 2007 LTRA. The plans developed to address the scenarios will be studied during 2008, and the results will then be reported by the regions for comparative purposes in 2009 LTRA. In the summer of 2008, the Planning Committee will be requested to prioritize emerging issues for possible scenario assessment plans developed in 2009 for study in 2010, using a simplified risk analysis approach. This process will continue in this fashion so that the LTRA will include not only the reference case, but also specific scenario analysis if a scenario is chosen by the PC. Figure 8 below outlines the enhanced process.

To implement Emerging Issues and Scenario analysis into the reliability assessment, the NERC Planning Committee adopted a process in December 2007 that includes identification of emerging issues, based on input from its subcommittees, for possible regional and NERC-wide evaluation. Transmission and resource (including internal demand) emerging issues will be proposed for Planning Committee consideration, and if an issue is selected for a scenario assessment, this scenario would be provided for regional entity reliability assessment as part of the data requests. Based on input from the industry, analysis could include both adequacy and security issues which are affected by issues such as:

- Substantial Non-dispatchable Resources Penetration
- High level of Demand Response Penetration\(^{43}\)
- Weather uncertainty evaluation

\(^{43}\) This activity has been taken up by the (Demand-Side Management Task Force), under the direction of the Resource Issues Subcommittee.
PC selected scenarios should be summarized by the Regional Entities as part of their submitted regional assessments. Full reports could be provided to NERC as supporting documentation for regional and long-term reliability assessments when they become available. Figure 8 shows the recommended flowchart for this process (as approved by the PC in December 2007).

Figure 8: 2008 Emerging Issues and Scenario Analysis

Guidelines for Submittal

For consistent submittal, a template for scenario submittal was developed by the Reliability Assessment Subcommittee. The risk assessment process the PC will follow was also outlined in this template, and shown below.

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44 Confidential Information will be handled by NERC staff, following Section 1500 of NERC’s Rules 7 Procedures (http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20081219.pdf)
**Emerging Issue Template**

**Background**

Each year, the 10-year *Long-Term Reliability Assessment* (LTRA) forms a basis for the NERC *reference case*. The reference case is generally based on the assumption that policy/regulations will be constant throughout the studied timeframe and a variety of economic trends, weather patterns and system equipment behaves as expected, usually based on historic performance trends.

Emerging issue analysis supports the development of scenarios, analysis of which can indicate the sensitivity of the reference case to changes in pre-specified conditions and provide insight into risks to regional reliability. Development of a small set of scenarios for comparison to the *reference case* is a valuable way to better understand the robustness of the reference case and to study potential impacts of scenarios on reliability.

In support of this effort, NERC’s Planning Committee (PC) has charged the Transmission Issues, Resource Issues and Reliability Assessment Subcommittees each to submit 3 to 5 high priority plausible emerging issues that could impact the bulk power system reliability over the next 10 years.

The PC will then prioritize the resulting emerging issues using a risk assessment matrix (Attachment I) and, based on the results and PC member judgments, they may select potential scenario(s) for study in the future. For each emerging issue, it is important to understand the impact on bulk power system reliability and influence on planning, operations and resources plans.

**Emerging Issue Qualification**

To qualify for consideration in this process, candidate emerging issues must meet the following criteria:

- Subcommittees should have a high degree of confidence that the emerging issue to be evaluated would affect the reliability of the bulk power system for more than a single year in the LTRA time period (10 year assessment window)
- The effects of the emerging issue on reliability are projected to be seen in the region no sooner than 3 years out, to allow sufficient time for analysis
- The effects of the emerging issue should represent a potentially significant impact to the bulk power system reliability across at least a regional footprint, and should not be a local/subregional reliability issue more effectively assessed by the affected Transmission Planners/Planning Authorities.
Template for Emerging Issue Submittal

For each candidate emerging issues, submitted provide:

<table>
<thead>
<tr>
<th>Emerging Issue #X: Title of Emerging Issue here.</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Horizon</strong></td>
<td>Number of years</td>
<td></td>
</tr>
<tr>
<td><strong>Background</strong></td>
<td>What is the change from the reference case?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>What changes during the 10-year horizon?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>What is the impact to regional reliability?</td>
<td></td>
</tr>
<tr>
<td><strong>Assessment Factors</strong></td>
<td>Resource Adequacy Considerations [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Transmission Adequacy Considerations [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Resource Siting Impacts [Yes/No]?</td>
<td></td>
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<tr>
<td></td>
<td>Operations Impacts [Yes/No]?</td>
<td></td>
</tr>
<tr>
<td><strong>Potential Study Scenarios (optional)</strong></td>
<td>Describe assumptions</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Provide guidance on future studies</td>
<td></td>
</tr>
</tbody>
</table>

The information in this table should be of sufficient detail to allow the PC to conduct its risk assessment & ranking exercise. The optional Potential Study Scenarios section, if completed, can assist the RAS in understanding how the emerging issue could impact bulk system reliability. Additional information will be collected by RAS for those emerging issues that are selected and approved by the PC for consideration in the LTRA assessment cycle.

An example can be found in Attachment II, in this section.

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45 If “Yes” explain how this item could be affected


### Attachment I

**Risk Assessment of Emerging Issues**

**Reliability Impact Ranking:**

The following question IS DESIGNED TO GATHER information on your view of each of the emerging issues below along with your RANKING of the LIKELIHOOD and how SEVERE the impact would be on bulk power system reliability.

**INDIVIDUAL RESPONSES WILL BE KEPT CONFIDENTIAL.**

What do you believe is the LIKELIHOOD of occurrence and how SEVERE the impact would be on bulk power reliability for each of the following?

Please indicate H (High), M (Medium), or L (Low).

<table>
<thead>
<tr>
<th>Issue</th>
<th>Likelihood 1-5 Years</th>
<th>Consequence 1-5 Years</th>
<th>Likelihood 6-10 Years</th>
<th>Consequence 6-10 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
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<tr>
<td>Emerging Issue #1</td>
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<td>Emerging Issue #2</td>
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<tr>
<td>Emerging Issue #3</td>
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<tr>
<td>Etc.</td>
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</tr>
</tbody>
</table>

### Ranking – User Identified

<table>
<thead>
<tr>
<th>User Identified Issue</th>
<th>Likelihood 1-5 Years</th>
<th>Consequence 1-5 Years</th>
<th>Likelihood 6-10 Years</th>
<th>Consequence 6-10 Years</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>H M L</td>
<td>H M L</td>
<td>H M L</td>
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<td>Emerging Issue #1</td>
<td></td>
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<tr>
<td>Etc.</td>
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</tbody>
</table>
## Attachment II
### Example Emerging Issue Submittal

Emerging Issue #X: Accelerated integration of renewable capacity

<table>
<thead>
<tr>
<th>Horizon</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of years</td>
<td>10 years</td>
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<table>
<thead>
<tr>
<th>Background</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>What is the change from the reference case?</td>
<td>Significant penetration of renewable and demand response resources (up to 15% of all energy)</td>
<td></td>
</tr>
<tr>
<td>What changes during the horizon?</td>
<td>Ramp to 15% energy should not be instantaneous, but at a rate that can be integrated while sustaining bulk power system reliability. Renewable and demand response resources in place at the end of 10 years.</td>
<td></td>
</tr>
<tr>
<td>What is the impact to regional reliability?</td>
<td>Weather patterns of the region/subregion, the variety of renewable sources installed, the existing generation mix, and the bulk power system transfer capability with neighboring areas all influence amount of penetration of variable resources. Another consideration is the availability of ancillary services and system re-dispatch needed to support reliable operation.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Assessment Factors</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource Adequacy Considerations [Yes/No]?</td>
<td>Yes. Significant changes in capacity mix: both in fuel and type. Incorporating both renewable and demand response will require new planning and operational strategies.</td>
<td></td>
</tr>
<tr>
<td>Transmission Adequacy Considerations [Yes/No]?</td>
<td>Yes. Significant increase in transmission requirements may be required to support the delivery of the renewable resources.</td>
<td></td>
</tr>
<tr>
<td>Resource Siting Impacts [Yes/No]?</td>
<td>Yes. Wind is not a portable fuel and must be sited where it is prominent.</td>
<td></td>
</tr>
<tr>
<td>Operations Impacts [Yes/No]?</td>
<td>Yes. Managing the variability of the generating resources and demand response will require more flexibility in the power system. The changes in the bulk power system flows from both the variable generation and demand response implementation must be better understood.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Potential Study Scenarios (optional)</th>
<th>Item</th>
<th>Specifics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Describe assumptions</td>
<td>Accommodate a minimum of an additional 15% of total energy from new renewable sources, with no more than 5% made up from energy efficiency. The base year for energy is 2008</td>
<td></td>
</tr>
<tr>
<td>Provide guidance on future studies</td>
<td>Substantial change in on-peak (demand response and variable/traditional capacity) and off-peak a(variable generation) capacity mix could influence reliability, as planning approaches need more study. Namely, what are the appropriate tests to perform to ensure bulk power system reliability? Further, transmission requirements may significantly change.</td>
<td></td>
</tr>
</tbody>
</table>

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46 If “Yes” explain how this item could be affected
Chapter 10—Additional Reliability Assessment Information

In order for NERC to independently assess the reliability of the Reporting Regions, each Reporting Region should address additional potential issues that could significantly impact reliability. Such potential issues include, but are not limited to, the following:

a) Peak load uncertainties and variability due to extreme weather, economic conditions, fuel prices, etc.

b) Transient dynamics, voltage, or small signal stability issues.

c) Fuel Supply and Delivery interruptions.

d) Aging infrastructure.

e) Catastrophic Events/ Extreme Contingencies; for example, loss of a fleet of generator due to pipeline failure, loss of major import path, etc.
Chapter 11—NERC Reliability Assessment Procedures

The majority of the work coordinated by NERC is governed by the *Rules of Procedure*. For the Reliability Assessments Program, it states:

The scope of the reliability assessment program shall include:

- Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected bulk power systems, both existing and as planned.

- Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

- Review, analyze, and report on regional self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

- Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on bulk power system reliability.

- Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the bulk power systems.

- The reliability assessment program shall be performed in a manner consistent with the reliability standards of NERC including but not limited to those that specify reliability assessment requirements.

**Reliability Assessment Reports**

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission...
adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and interconnection basis as conditions warrant, or as requested by the board or applicable governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key reliability issues and their impacts on the reliability of a regions, subregions, or interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected bulk power systems in North America.

**Reliability Assessment Data and Information Requirements**

To carry out the reviews and assessments of the overall reliability of the interconnected bulk power systems, the regional entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.
Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a critical energy infrastructure information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the regional entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the bulk power systems. In connection with the reliability assessment reports, requests shall be submitted to each of the regional entities for required reliability assessment data and other information, and for each region’s self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The regional self-assessments are to be conducted in compliance with NERC standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the regional entities as needed. The summary of the regional self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC’s request. This outline may change from time to time as key reliability issues change.

In general, the regional reliability self-assessments shall address, among other areas, the following topics: demand and net energy for load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to load; and any other reliability issues in the region and their potential impacts on the reliability of the bulk power systems.

**Reliability Assessment Process**

Based on their expertise, the review of the collected data, the review of the regional self-assessment reports, and interviews with the regional entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each region’s existing and planned bulk power system. The results of the review teams shall form the basis of NERC’s long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the region. The team shall independently evaluate the ability of the regional entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the region. If the region relies on capacity from outside of the region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the regional entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the regional entity and its members. For cases of
inadequate capacity or reserve margin, the regional entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the regional entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC reliability standards. If sub-areas of the regional system are especially critical to the reliable operation of the regional bulk transmission system, these facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems, operational readiness of the affected regional entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the regional entity’s ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the regional entities and the North American interconnected bulk power system for the period of the assessment. While the regional entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the regional entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America. The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

In addition to providing long-term and seasonal assessments in connection with the reliability assessment program, the review team of experts shall also be responsible for recommending new
and revised reliability standards related to the reliability assessments and the reliability of the bulk power systems. These proposals for new or revised standards shall be entered into NERC’s Standards Development Process.

Upon completion of the assessment, the team shall share the results with the regional entities. The regional entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC’s technical review team and NERC. The preparation and approval of NERC’s reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees.

The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the board for publication to the electric industry.

**The Reliability Assessment Subcommittee (RAS)**

The primary goal of the RAS is to provide an independent assessment of the reliability of the Regions and the North American system for the period of the report. RAS reviews, assesses, and reports on the overall reliability (adequacy and operating reliability) of the regional (including subregional) and interregional bulk power systems, both existing and as planned. Those reviews and assessments verify that each Region (and subregion) conforms to its own planning criteria and guides and NERC’s Reliability Planning Standards. The RAS relies on the Regions to provide the information to perform such assessments. However, even though the RAS is dependent upon the Regions for the information, the RAS is not required to accept the conclusions provided by the Regions.

The subcommittee is comprised of the following:

- Chair
- Vice Chair
- One representative and one alternate from each Regional Entity Staff
- One representative from the NERC Operating Committee
- One member-at-large representing Canada
- At least one representative from:
  - Investor Owned Utility
  - Areas where there are no organized markets
- Additional members can be added:
  - At the request of the PC sector representatives
  - As needed by the NERC Coordinator
- Reliability Assessment Working Group Chairs
- NERC staff coordinator(s)
- Liaison Members include:
  - Federal Energy Regulatory Commission
  - United States Department of Energy
    - National Energy Board, Canada

Guest participation of industry experts may be requested to support reliability assessments.
The RAS strives to achieve consensus in its decisions. The assessments that are made are based on the best information available at the time. There is judgment applied to this information, so that legitimate differences of opinion can develop. Despite these differences of opinion, the RAS will work as a team to achieve consensus on its findings. The conclusions and recommendations of RAS reports are more compelling when consensus is achieved. However, there will be cases where consensus cannot be reached among the RAS members. In those cases, the following process will be invoked. The point of disagreement will be put to a vote of the RAS members present at the meeting (each RAS member will get one vote). The chair and the vice chair of the RAS will not vote. However, the chair will cast the tie-breaking vote if the vote is tied. The vice chair will perform this role if the chair is not present at the meeting.

The viewpoint receiving the majority of the votes becomes the majority opinion. The other viewpoint becomes the minority viewpoint. Both viewpoints are published in the report. A footnote shall be added which will contain the results of the point of disagreement vote, indicating which members supported the majority and minority positions.

If the above process is unsatisfactory to either the RAS or the Regions, either party can petition the PC and the NERC Dispute Resolution Process can be invoked.

**Reliability Assessment Procedure – Long-Term Reliability Assessment**

**A. Data Requests to the Regions**

RAS will annually submit a request for data to each of the NERC Regions. The timing of the request will be governed by the schedule for the preparation of the report.

Each of the Regions will be required to submit its Regional data and a reliability assessment. The Regional assessment will be carried out in accordance with Regional procedures that are required by the NERC Planning Standards. The following data, as a minimum, will be requested from the Regions:

- Demand forecast data
- Resource capacity plans
- This information will generally include portions of the EIA-411 submittal related to resource capacity
- Transmission construction plans
- Regional assessment reports
- Interregional planning or operating study reports

The data will be submitted to NERC in accordance with the format prescribed by NERC Staff. Other information and reports will be forwarded to RAS, typically in summary form or through interviews of the Regions by RAS. In addition, the RAS will request the Regions to provide information regarding how the Regions comply with the NERC Planning Standards.
B. RAS Review of Regional Data and Reliability Assessments

Resource Adequacy Assessment
The Regional demand and resource capacity data will be reviewed for completeness and assessed in the context of the overall resource capacity needs of the Region. RAS will make an independent assessment of the ability of the Region to serve its obligations given the demand growth projections, the amount of non-committed or contracted capacity, etc. The RAS will determine if the resource information submitted represents a reasonable and attainable plan for the Region.

The demand and resource capacity information will be compared to the reserve objective of the Region for all time frames presented. In addition, if the Region relies on capacity from outside the Region to meet its objectives, the ability to deliver that capacity will be factored into the assessment. If the resulting capacity margin meets the Regional objective, the system is judged to be adequate.

For cases of inadequate capacity margin, the Region will be requested to analyze and explain to the RAS any capacity inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions.

In the case of the North American Interconnections, the Regional capacity data will be aggregated to assess resource adequacy for the entire Interconnection. In this assessment, interregional transmission transfer capabilities will be evaluated to determine whether there are transmission constraints that could limit the deliverability of available capacity throughout the Interconnection. The results of this analysis are to be reported in the assessment report.

C. Transmission Adequacy and Security Assessment

RAS will be provided with information that relates to the strength and security of the Regional transmission system. Such information might include:

- Regional planning study reports
- Interregional planning study reports
- Regional operational study reports
- Regional operating data
- Regional disturbance analysis reporting

This information will be reviewed and analyzed. If additional information is required, another data request will be sent to the Region. The assessment will provide a judgment on the ability of the Regional transmission system to operate securely under the expected range of operating conditions over the assessment period as required by the NERC Planning Standards. In addition, the assessment will consider unusual but possible operating scenarios and how the system is expected to perform. If there are subareas of the Regional system or facilities that are especially critical to the reliable operation of the Regional transmission system, these facilities or subareas will be reviewed and addressed in the assessment. Any
areas of concern related to the adequacy or security of the system will be identified in the assessment.

D. Regional Process Review

An important part of the RAS assessment process is to review the effectiveness of the Regional assessment processes and consequently the overall compliance of the Region to the NERC Planning Standards. In addition to the information and reports provided by the Regions, RAS will interview representatives of the Regions who are responsible for implementing the Regional assessment process. The purpose of the interviews is to identify any problems with the process and to acquire supplementary information that may not be available within the Regional assessment reports. Interviews will be conducted annually.

The results of the Regional process review shall be documented and feedback is to be provided to the Regions and posted on the NERC web site. Any rebuttal that the Region provides will be similarly posted.

E. Reporting of Assessment Result

Upon completion of the assessment, the results will be shared with the Regions. The Regions will have the opportunity to rebut the points made in the assessment. Normally, the RAS and the Regions will agree on the contents of the assessment and editorial changes will be made to the mutual satisfaction of the RAS and the Regions. In cases where disagreement cannot be resolved, the RAS will state its position in the RAS report. The Regions will have an opportunity to provide alternative opinions to the RAS position and the Regional rebuttal opinions will be included in the RAS report.

The RAS will prepare the Reliability Assessment report and present it for approval to the Planning Committee and the Board of Trustees in accordance with the schedule. Upon approval, the report will be published and posted on the NERC web site.

Reliability Assessment Procedure – Seasonal Reliability Assessment

A. Data Request to the Regions

The RAS will seasonally submit a request for data to each of the NERC Regions. The timing of the request will be governed by the schedule for the preparation of the report. The Regions will be expected to respond promptly to the data request. This request will generally be less comprehensive than that required for the 10-year assessment. Also, due to seasonal differences and the near-term time frame, the data requests can be expected to vary seasonally and annually.
B. Resource Adequacy Assessment

The Regional demand and resource capacity information will be reviewed for completeness and assessed in the context of the overall resource needs for the Region for that season. If the Region relies on capacity from outside the Regions to meet its resource objectives, the ability to deliver that capacity will be factored into the assessment. The demand and resource capacity information will be compared to the reserve objective of the Region for the season being assessed. If the capacity meets the Regional objective, the system is judged to be adequate.

In addition, the RAS will make an independent assessment of the ability of the Region to serve its obligations given the demand growth projections, the amount of non-committed or contracted capacity, etc. The RAS will determine if the information represents a reasonable and attainable plan for the Region.

For cases of inadequate capacity, the analysis should be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist. The results of this analysis are to be reported in the assessment report.

C. Transmission Adequacy and Operating Reliability Assessment

RAS will have access to information that relates to the strength and security of the Regional transmission system. Such information might include:

- Regional planning study reports
- Interregional planning study reports
- Regional operational study reports
- Regional operating information
- Regional disturbance analysis reporting

This information will be reviewed and analyzed. If additional information is required, another data request will be sent to the Region. The assessment will provide a judgment on the ability of the Regional transmission system to operate securely under the expected range of operating conditions. In addition, the assessment will consider unusual but possible operating scenarios and how the system is expected to perform. If there are subareas of the Regional system or facilities that are especially critical to the reliable operation of the Regional transmission system, these facilities or subareas will be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system will be identified in the assessment.

D. Operational Assessment

In areas with potential resource adequacy or system security problems, RAS will review the operational readiness of the effected Regions for the upcoming season. Operational readiness will take into account a wide range of activities, all of which should reinforce the Region’s
ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include:

- Facility modifications and additions
- New or modified operating procedures
- Training of system operators
- Emergency procedures enhancement
- Planning and operating studies
- Improved communications protocols and procedures
- Enhanced (or extended) maintenance of facilities and equipment

E. Reporting of Assessment Results

Upon completion of the assessment, the results will be shared with the Regions. The Region will have the opportunity to rebut the points made in the assessment. Normally, the RAS and the Regions will agree on the contents of the assessment and editorial changes will be made to the mutual satisfaction of the RAS and the Regions. In cases where disagreement cannot be resolved, the RAS will state its position in the report. The Regions will have an opportunity to provide alternative opinions to the RAS position and the Regional rebuttal opinions will be included in the report.

After the satisfactory resolution of all comments, the report will be published and posted on the NERC website.

Sample Schedules for Reliability Assessments

Reliability Assessment Subcommittee has set the schedule below for the Long-Term Reliability Assessment:

<table>
<thead>
<tr>
<th>Date</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 24</td>
<td>Request letter for regional self assessments and data sent to regions</td>
</tr>
<tr>
<td>May 1</td>
<td>LTRA data due, in Excel spreadsheet, to NERC</td>
</tr>
<tr>
<td>May 15</td>
<td>Notice for required data corrections sent to regions</td>
</tr>
<tr>
<td>May 29</td>
<td>Data corrections due to NERC</td>
</tr>
<tr>
<td>June 5</td>
<td>Regional self assessments due to NERC</td>
</tr>
<tr>
<td>June 12</td>
<td>Draft report sent to RAS</td>
</tr>
<tr>
<td>June 23-25</td>
<td>RAS peer review meeting</td>
</tr>
<tr>
<td>July 30</td>
<td>LTRA open workshop</td>
</tr>
<tr>
<td>September 1</td>
<td>Draft LTRA to PC and MRC for review</td>
</tr>
<tr>
<td>September</td>
<td>PC Meeting: Review and comment</td>
</tr>
<tr>
<td>September 24</td>
<td>Final draft to NERC Board of Trustees</td>
</tr>
<tr>
<td>October 1</td>
<td>Target release and electronic publication of report</td>
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71
Reliability Assessment Subcommittee has set the schedule below for the *Summer Reliability Assessment*:

<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>January 21</td>
<td>Request letter for regional data and narrative write-ups to regions</td>
</tr>
<tr>
<td>March 31</td>
<td>Regional data and self-assessments write-ups due to NERC; NERC staff will format and forward narrative write-ups to RAS</td>
</tr>
<tr>
<td>April 7</td>
<td>NERC sends initial draft of complete report to RAS</td>
</tr>
<tr>
<td>April 16-17</td>
<td>RAS peer review meeting</td>
</tr>
<tr>
<td>April 25</td>
<td>RAS draft to NERC PC Executive Committee and MRC for review</td>
</tr>
<tr>
<td>May 2</td>
<td>Final draft to NERC Board of Trustees</td>
</tr>
<tr>
<td>May 9</td>
<td>NERC Board of Trustees Meeting for approval of report</td>
</tr>
<tr>
<td>May 16</td>
<td>Target release and electronic publication of report</td>
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Reliability Assessment Subcommittee has set the schedule below for the *Winter Reliability Assessment*:

<table>
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<tr>
<td>July 1</td>
<td>NERC sends request letter for regional data and narrative write-ups</td>
</tr>
<tr>
<td>September 30</td>
<td>Regional data and self-assessments write-ups due to NERC; NERC staff will format and forward narrative write-ups to RAS</td>
</tr>
<tr>
<td>October 3</td>
<td>NERC sends initial draft of complete report to RAS</td>
</tr>
<tr>
<td>October 15-16</td>
<td>RAS peer review meeting</td>
</tr>
<tr>
<td>October 24</td>
<td>RAS draft to NERC PC Executive Committee and MRC for review</td>
</tr>
<tr>
<td>October 31</td>
<td>PC Executive Committee Endorsement</td>
</tr>
<tr>
<td>November 10</td>
<td>Final draft to NERC Board of Trustees</td>
</tr>
<tr>
<td>November 17</td>
<td>NERC Board Meeting for approval of report</td>
</tr>
<tr>
<td>November 20</td>
<td>Target release and electronic publication of report</td>
</tr>
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NERC 2009 Long-Term Reliability Data Collection Forms

**Form ERO-2009LTR**
Please enter the reporting region, subregion and country below:

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<thead>
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<tr>
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<table>
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</table>

**Submission Date**

**Schedule 1A - Historical and Projected Peak Demand and Energy - Monthly**

| Line# | Category                        | Units | Year | Codes | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|-------|---------------------------------|-------|------|-------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| 01    | Actual - Peak Hour Demand       | MW    | 2008 | MDA   |     |     |     |     |     |     |     |     |     |     |     |     |
| 02    | Actual - Net Energy             | GwH   | 2008 | MNLA  |     |     |     |     |     |     |     |     |     |     |     |     |
| 03    | Reporting Year - Peak Hour Demand| MW    | 2009 | MDF   |     |     |     |     |     |     |     |     |     |     |     |     |
| 04    | Reporting Year - Net Energy     | GwH   | 2009 | MNLF  |     |     |     |     |     |     |     |     |     |     |     |     |
| 05    | Next Year - Peak Hour Demand    | MW    | 2010 | MDS   |     |     |     |     |     |     |     |     |     |     |     |     |
| 06    | Next Year - Net Energy          | GwH   | 2010 | MNLS  |     |     |     |     |     |     |     |     |     |     |     |     |

**Schedule 1B - Historical and Projected Peak Demand and Energy - Annual**

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### Schedule 3A & 3B - Demand and Capacity - Summer/Winter

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<td>Demand Response used for Reserves - Spinning</td>
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### FUTURE CAPACITY ADDITIONS

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### CONCEPTUAL CAPACITY

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### DELIVERABLE INTERNAL CAPACITY

#### 9

\[ 9 = 6a + 7a \]
### 10 CAPACITY TRANSACTIONS - IMPORTS

\[ 10 = 10a + 10b + 10c + 10d \]

- **10a** Firm (Note: The sum of 10a1 and 10a2 must be <= 10a)
  - **10a1** Full-Responsibility Purchases
  - **10a2** Owned Capacity/Entitlement Located Outside the Region/Subregion
- **10b** Non-firm
- **10c** Expected (Note: The sum of 10c1 and 10c2 must be <= 10c)
  - **10c1** Full-Responsibility Purchases
  - **10c2** Owned Capacity/Entitlement Located Outside the Region/Subregion
- **10d** Provisional – transactions under study, but negotiations have not begun.

### 11 CAPACITY TRANSACTIONS - EXPORTS

\[ 11 = 11a + 11b + 11c + 11d \]

- **11a** Firm (Note: The sum of 11a1 and 11a2 must be <= 11a)
  - **11a1** Full-Responsibility Sales
  - **11a2** Owned Capacity/Entitlement Located Outside the Region/Subregion
- **11b** Non-firm
- **11c** Expected (Note: The sum of 11c1 and 11c2 must be <= 11c)
  - **11c1** Full-Responsibility Sales
  - **11c2** Owned Capacity/Entitlement Located Outside the Region/Subregion
- **11d** Provisional – transactions under study, but negotiations have not begun.

### 12 EXISTING, CERTAIN CAPACITY & NET FIRM TRANSACTIONS

\[ 12 = 6a + \text{Net Firm Transactions} \]

### 13 DELIVERABLE CAPACITY RESOURCES

\[ 13 = 12 + 7a + \text{Net Expected Transactions} \]

### 14 PROSPECTIVE CAPACITY RESOURCES

\[ 14 = 13 + 6b - \text{Existing, Other Derates} + 16b \]

### 15 TOTAL POTENTIAL CAPACITY RESOURCES

\[ 15 = 13 + 6b - \text{Existing, Other Derates} + 8 + \text{Net Provisional Transactions} \]

### 15a ADJUSTED POTENTIAL CAPACITY RESOURCES

\[ 15a = 13 + 6b - \text{Existing, Other Derates} + 16b + 16d + \text{Net Provisional Transactions} \]
### Reliability Assessment Guidebook

#### NERC Reliability Assessment Procedures

<table>
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<tr>
<th>Capacity Margins</th>
<th>16a: Confidence of Future, Other (7b), using reasonable judgement</th>
<th>16b: Net Future, Other Resources After Confidence Percentage Is Applied = 7b*16a</th>
<th>16c: Confidence of Conceptual (8), using reasonable judgement</th>
<th>16d: Net Conceptual Resources After Confidence Percentage Is Applied = 8*16c</th>
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<td>17C: Region/Subregion Target Capacity Margin</td>
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#### Data Entries

- **Other Capacity < 1 MW**
- **Distributed Generator Capacity >= 1 MW**

- **Capacity Total from EIA-860**

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<td>Summary - margin calculations</td>
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### Schedule 4A - Capacity Imports/Incoming Transfers - Summer

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<th>Other Region</th>
<th>Other Subregion</th>
<th>Other Party EIA Code</th>
<th>Other Party Name</th>
<th>Plant ID</th>
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<th>2012</th>
<th>2013</th>
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</table>

### Schedule 4B - Capacity Imports/Incoming Transfers - Winter

| Other Country | Other Region | Other Subregion | Other Party EIA Code | Other Party Name | Plant ID | Unit ID | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---------------|-------------|-----------------|---------------------|------------------|---------|--------|------|------|------|------|------|------|------|------|------|------|
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |

### Schedule 4C - Capacity Exports/Outgoing Transfers - Summer

| Other Country | Other Region | Other Subregion | Other Party EIA Code | Other Party Name | Plant ID | Unit ID | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---------------|-------------|-----------------|---------------------|------------------|---------|--------|------|------|------|------|------|------|------|------|------|------|
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |

### Schedule 4D - Capacity Exports/Outgoing Transfers - Winter

| Other Country | Other Region | Other Subregion | Other Party EIA Code | Other Party Name | Plant ID | Unit ID | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---------------|-------------|-----------------|---------------------|------------------|---------|--------|------|------|------|------|------|------|------|------|------|------|
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |
|               |             |                 |                     |                  |         |        |      |      |      |      |      |      |      |      |      |      |      |
### Schedule 5 - Transmission Line Circuit Miles

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<th>121-150</th>
<th>151-199</th>
<th>200-299</th>
<th>300-399</th>
<th>400-599</th>
<th>600+</th>
<th>Total AC</th>
<th>200-299</th>
<th>300-399</th>
<th>400-599</th>
<th>600+</th>
<th>Total DC</th>
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<td>Under Construction as of 1/1/2009</td>
<td>Circuit Miles</td>
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<tr>
<td>Planned - Completed within first five years</td>
<td>Circuit Miles</td>
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<tr>
<td>Conceptual - Completed within first five years</td>
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<tr>
<td>Planned - Completed within second five years</td>
<td>Circuit Miles</td>
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<tr>
<td>Conceptual - Completed within second five years</td>
<td>Circuit Miles</td>
<td>TLCS</td>
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### Schedule 6A - Projected Transmission Line Additions (100kV and above)

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<th>Primary Driver (Choose One)</th>
<th>Primary Driver (Choose One)</th>
<th>Tie Line? (Yes/No)</th>
<th>Project Name</th>
<th>Terminal From Location</th>
<th>Terminal To Location</th>
<th>Company Name</th>
<th>EIA Company Code</th>
<th>Type of Entity (C,F,I,M,S,O)</th>
<th>Percent Ownership</th>
<th>Line Length in Circuit Miles</th>
<th>Line Type (OH, UG, SM)</th>
<th>Voltage Type (AC or DC)</th>
<th>Voltage Operating (kV)</th>
<th>Voltage Design (kV)</th>
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<table>
<thead>
<tr>
<th>Conductor Material Type (AL, ACSR, CU, OT)</th>
<th>Bundling Arrangement (1, 2, 3, 4, OT)</th>
<th>Circuits Per Structure Present</th>
<th>Circuits Per Structure Ultimate</th>
<th>Pole/Tower Material (W,C,S,B,P,O)</th>
<th>Pole/Tower Structure Type (P,H,T,U,O)</th>
<th>Capacity Rating (MVA)</th>
<th>Expected In Service Month (MM)</th>
<th>Expected In Service Year (YYYY)</th>
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79
Schedule 6B - Projected Transformer Additions (200 kV Low-Side and above)

<table>
<thead>
<tr>
<th>Transformer Project Name</th>
<th>High-Side Voltage (kV)</th>
<th>Low-Side Voltage (kV)</th>
<th>Expected In-Service Date (MM-YYYY)</th>
<th>Description/Status</th>
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Schedule 7B - Annual Data on Transmission Line Outages for EHV D.C. Lines

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<thead>
<tr>
<th>Applicable D.C. Voltage Class</th>
<th>± 100-199 kV</th>
<th>± 200-299 kV</th>
<th>± 300-399 kV</th>
<th>± 400-499 kV</th>
<th>± 500 kV or greater</th>
</tr>
</thead>
</table>

1. Applicable D.C. Voltage Class

Schedule 7A - Annual Data on Transmission Line Outages for EHV A.C. Lines

1. Applicable A.C. Voltage Class | 230 kV | 345 kV | 500 kV | 765 kV | Other |

2. Scheduled Outages for Specified Voltage Class

2. Number of Scheduled Outages

3. Number of Circuits Involved

4. Scheduled Circuit-Hours Out of Service

5. Unscheduled Outages for Specified Voltage Class

5. Number of Non-Momentary Unscheduled Outages

6. Number of Circuits Involved

7. Unscheduled Circuit-Hours Out of Service

8. Causal Categories for Unscheduled Outages of Specified Voltage Class (Percent)

8. Weather

9. Animals, Fire and Smoke, Human Accidents

10. Vegetation

11. Operator Action

12. Equipment Failure

13. Unknown

14. Other
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<tr>
<th>Category</th>
<th>Code</th>
<th>Actual</th>
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<td><strong>PART I - Existing, Certain Resources</strong></td>
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If fuels do not equal line 6a from Schedule 3A/3B - Demand and Capacity - Summer/Winter, please explain here:
### Schedule 9A & 9B - Fuel-Type Breakdown - Summer/Winter (Continued)

#### PART II - Future, Planned Resources

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<th>FCSBM</th>
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<th>FCSCCG</th>
<th>FCSCCDF</th>
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<th>FCSUN</th>
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### PART III - Conceptual Resources

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NERC 2009 Long-Term Reliability Data Collection Form Instructions

**Schedules 1A and 1B – Historical and Projected Peak Demand and Energy** (supports Form EIA-411 submittal)

Schedule 1 is to be reported in total by each Regional Entity for all utilities, groups of utilities, such as Subregional Entities, Independent System Operators, or Regional Transmission Operators, within that Region. The reported peak demand for a Region or Subregion should be **non-coincident**, comprised of the sum of all peak demands for the various operating entities within a NERC Region or Subregion during the specified period. (Only file a coincident peak if the coincident and non-coincident values are equal.)

Schedule 1A - Enter monthly peak hour demands and net energy for load for designated years in lines 1 through 6.

Schedule 1B - Enter seasonal peak hour demands and net energy for load for designated years in lines 7 through 9.

**Schedules 3A and 3B – Demand and Capacity – Seasonal**

**Line 1 – Unrestricted Non-coincident Peak Demand = 2+1a+1b-1c-1d**
The gross load of the region/sub-region, assuming no load management or increased energy efficiency impacts, and no diversity between reporting entities.

**Line 1a – New Conservation (Energy Efficiency)**
The estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth.

**Line 1b – Estimated Diversity**
The difference between the region’s/sub-region’s peak and the sum of the peaks of the reporting entities (LSEs, control areas, zones, etc.). GUIDANCE: Only provide this data if the reporting area currently uses diversity.

**Line 1c – Additions for non-member load (load served by non-registered LSE's in a region)**
Adjustments to account for load of non-members, following the NERC standard MOD-16 “data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.”

**Line 1d – Stand-by Load Under Contract (Normally served by behind the meter generation)**
The load specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer’s primary source. Stand-by Load is intended to be used infrequently by any one customer.
Line 2 – Total Internal Demand
The sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back). Adjustments for controllable demand response should not be incorporated in this value.

Line 2a – Direct Control Load Management
Dispatchable, Controllable, Demand-side management that is under direct remote control of a control center. It is the magnitude of customer demand that can be interrupted at the time of the Regional Entity’s seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises.

Line 2b – Contractually Interruptible (Curtailable)
Dispatchable, Controllable, Demand-side management achieved by a customer reducing its load upon notification from a control center. The interruption must be mandatory at times of system emergency. Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity’s seasonal peak. In some instances, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.

Line 2c – Critical Peak-Pricing (CPP) with Control
Dispatchable, Controllable, Demand-side management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.

Line 2d – Load as a Capacity Resource
Dispatchable, Controllable, Demand-side management which acts as a capacity resource to commit to pre-specified load reductions during certain system conditions. This resource is capable of controlling demand in a responsive, measurable, and verifiable manner within time limits. This resource is called to perform at the direction of the Control Area and may be limited by the number of calls per month and/or the number of hours each month it may perform. Values reported on this line reduce peak demand, represented in Line 3 – Net Internal Demand.

Line 3 – Net Internal Demand 2-2a-2b-2c-2d
Total Internal Demand less Dispatchable, Controllable Demand Response used for Capacity (Direct Control Load Management less Contractually Interruptible less Critical Peak-Pricing less Load as a Capacity Resource).
NOTE: Data entered in lines 4a through 4d are for information only and will not be used to adjust Net Internal Demand although some of these resources may make up a portion of lines 2a through 2c\(^{47}\).

**Line 4a – Demand Response used for Reserves - Spinning**
Demand-side resources which displace generation deployed as operating reserves that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event. Penalties are assessed for non-performance.

**Line 4b – Demand Response used for Reserves - Non-Spinning**
Demand-side resources which displace generation deployed as operating reserves that are not connected to the system but capable of serving demand within a specified time. Penalties are assessed for non-performance.

**Line 4c – Demand Response used for Regulation**
Demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin.

**Line 4d – Demand Response used for Energy, Voluntary - Emergency**
Demand-side resources which curtails voluntarily when offered the opportunity to do so for compensation. Demand-side resource curtails during system and/or local capacity constraints.

**Line 5 – Total Internal Capacity = 6+7**
The sum of All Existing and Planned Capacity Additions

**Line 6 – Existing Capacity/Existing Capacity Adjusted for Net of All Re-ratings, Retirements and Adjustments (“iron in the ground”) = 6a+6b+6c**
This capacity is all existing generation connected to the electric system for the purpose of supplying electric load as of 12/31/2008. Existing capacity does not include generation serving customers behind the meter. Customer load included by the Load Serving Entity is the customer load reduced by any behind the meter generation.

**Line 6a – Existing, Certain**
Existing generation resources available to operate and deliver power within or into the region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:
- Contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment.
- Where organized markets exist, designated market resource\(^{48}\) that is eligible to bid into a market or has been designated as a firm network resource.

\(^{47}\) Zero can be a legitimate answer

\(^{48}\) Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.
- Network Resource\textsuperscript{49}, as that term is used for FERC \textit{pro forma} or other regulatory approved tariffs.
- Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed\textsuperscript{50}
- Capacity resources that can not be sold elsewhere
- Other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed\textsuperscript{51} during the period of analysis in the assessment

**Line 6a1 – Wind Expected On-Peak**
The amount of existing wind capacity that is expected to be available on seasonal peak.

**Line 6a2 – Solar Expected On-Peak**
The amount of existing solar capacity that is expected to be available on seasonal peak.

**Line 6a3 – Hydro Expected On-Peak**
The amount of existing hydro capacity that is expected to be available on seasonal peak.

**Line 6a4 – Biomass\textsuperscript{52} Expected On-Peak**
The amount of existing biomass capacity that is expected to be available on seasonal peak.

**Line 6a5 – Load as a Capacity Resource Expected On-Peak (Load Management Programs)**
Dispatchable, Controllable, Demand-side management which acts as a capacity resource to commit to pre-specified load reductions during certain system conditions. This resource is capable of being interrupted upon demand in a responsive, measurable, and verifiable manner within time limits, and local generators, rated 100 kV or higher not visible to the Control Area's dispatch system. This resource is called to perform at the direction of the Control Area and may be limited by the number of calls per month and/or the number of hours each month it may perform. \textit{Values reported on this line are treated as a capacity resource and are held to the same expectations as an Existing, Certain resource. Only the expected on-peak seasonal capacity is reported on this line.}

**Line 6b – Existing, Other**
Existing generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing, Certain. This category includes, but is not limited to the following:
- A resource with non-firm or other similar transmission arrangements
- Energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason

\textsuperscript{49} Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{50} Energy only resources with transmission service constraints are to be considered as Existing, Other

\textsuperscript{51} Energy only resources with transmission service constraints are to be considered as Existing, Other

\textsuperscript{52} \textbf{Biomass} as defined by EIA: Organic non-fossil material of biological origin constituting a renewable energy source (wood, wood waste, municipal solid waste, landfill gas, ethanol and other biomass).
- Mothballed generation (that may be returned to service for the period of the assessment)
- Portions of variable generation not counted in the Existing, Certain category (e.g. wind, solar, etc. that may not be available or de-rated during the assessment period)
- Hydro generation not counted as Existing, Certain or de-rated
- Generation resources constrained for other reasons

**Line 6b1 – Wind Derated On-Peak**
The amount of existing wind capacity that is expected to be unavailable on seasonal peak.

**Line 6b2 – Solar Derated On-Peak**
The amount of existing solar capacity that is expected to be unavailable on seasonal peak.

**Line 6b3 – Hydro Derated On-Peak**
The amount of existing hydro capacity that is expected to be unavailable on seasonal peak. Pumped storage would not be considered as hydro.

**Line 6b4 – Biomass Derated On-Peak**
The amount of existing biomass capacity that is expected to be unavailable on seasonal peak.

**Line 6b5 – Load as a Capacity Resource Derate On-Peak (Load Management Programs)**
Dispatchable, Controllable, Demand-side management which acts as a capacity resource to commit to pre-specified load reductions during certain system conditions. This resource is capable of being interrupted upon demand in a responsive, measurable, and verifiable manner within time limits, and local generators, rated 100 kV or higher not visible to the Control Area's dispatch system. This resource is called to perform at the direction of the Control Area and may be limited by the number of calls per month and/or the number of hours each month it may perform. *Values reported on this line are treated as a capacity resource and are held to the same expectations as an Existing, Other resource. Only the derated on-peak seasonal capacity is reported on this line.*

**Line 6b6 – Energy Only**
Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

**Line 6b7 – Schedules Outage – Maintenance**
Capacity reduction due to a generator outage that is scheduled well in advance and is of a predetermined duration.

**Line 6b8 – Transmission-Limited Resources**
The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load within the region.

*Example:* If capacity is limited by both studied transmission limitations and generator derates, the generator derates take precedence. For example a 100 MW wind farm with a wind capacity variation reduction of 50 MW and a transmission limitation of 60 MW
would take the 50 MW wind variation reduction first and list 10 MW in the transmission limitation.

**Line 6c – Existing, Inoperable**

This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero (0). This includes all existing generation not included in categories Existing, Certain or Existing Other, but is not limited to, the following:

- Mothballed generation (that can not be returned to service for the period of the assessment)
- Other existing but out-of-service generation (that can not be returned to service for the period of the assessment)
- This category does not include behind-the-meter generation or non-connected emergency generators.
- This category does not include partially dismantled units that are not forecasted to return to service

**NOTE:** All existing generation resources must be counted on lines 6a, 6b or 6c and should not be double counted between these three categories. Where categorization as to the Existing, Certain and Existing, Other category is not clear, the generation should be designated as Existing, Other.

**Line 7 – Future Capacity Additions = 7a+7b**
The sum of Future, Planned and Future, Other Capacity additions as defined below.

**NOTE:** The following Future categories include generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

- Construction has started
- Regulatory permits being approved, any one of the following:
  - Site permit
  - Construction permit
  - Environmental permit
- Regulatory approval has been received to be in the rate base
- Approved power purchase agreement.
- Approved and/or designated as a resource by a market operator

**Line 7a – Future, Planned**
Generation resources anticipated to be available to operate and deliver power within or into the region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

- Contracted (or firm) or other similar resource
• Where organized markets exist, designated market resource\textsuperscript{53} that is eligible to bid into a market or has been designated as a firm network resource.
• Network Resource\textsuperscript{54}, as that term is used for FERC \textit{pro forma} or other regulatory approved tariffs.
• Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed\textsuperscript{55}
• Where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve

**Line 7a1 – Wind Expected On-Peak**
The amount of planned wind capacity that is expected to be available on seasonal peak.

**Line 7a2 – Solar Expected On-Peak**
The amount of planned solar capacity that is expected to be available on seasonal peak.

**Line 7a3 – Hydro Expected On-Peak**
The amount of planned hydro capacity that is expected to be available on seasonal peak.

**Line 7a4 – Biomass Expected On-Peak**
The amount of planned biomass capacity that is expected to be available on seasonal peak.

**Line 7b – Future, Other**
This category includes future generating resources that do not qualify as Future, Planned and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that may:
• Be curtailed or interrupted at any time for any reason
• Energy-only resources that may not be able to serve load during the period of analysis in the assessment
• Variable generation not counted in the Future, Planned category or may not be available or is de-rated during the assessment period
• Hydro generation not counted in the Future, Planned category or de-rated

Only the net expected on-peak capacity is included in this line and does not include Energy Only.

Resources included in this category may be adjusted using a confidence factor (%), Line 16a, to reflect uncertainties associated with siting, project development or queue position.

**Line 7b1 – Wind Expected On-Peak**
The amount of planned wind capacity that is expected to be available on seasonal peak.

**Line 7b2 – Wind Derate On-Peak**
The amount of proposed wind capacity that is expected to be unavailable on seasonal peak.

\textsuperscript{53}Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{54}Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

\textsuperscript{55}Energy only resources with transmission service constraints are to be considered in category Existing, Other.
Line 7b3 – Solar Expected On-Peak
The amount of planned solar capacity that is expected to be available on seasonal peak.

Line 7b4 – Solar Derate On-Peak
The amount of proposed solar capacity that is expected to be unavailable on seasonal peak.

Line 7b5 – Hydro Expected On-Peak
The amount of planned hydro capacity that is expected to be available on seasonal peak.

Line 7b6 – Hydro Derate On-Peak
The amount of proposed hydro capacity that is expected to be unavailable on seasonal peak.

Line 7b7 – Biomass Expected On-Peak
The amount of planned biomass capacity that is expected to be available on seasonal peak.

Line 7b8 – Biomass Derate On-Peak
The amount of proposed biomass capacity that is expected to be unavailable on seasonal peak.

Line 7b9 – Energy Only
Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Line 8 – Conceptual
This category includes generation resources that are not in a prior listed category, but have been identified and/or announced on a resource planning basis through one or more of the following sources:
- Corporate announcement
- Entered into or is in the early stages of an approval process
- Is in a generator interconnection (or other) queue for study\(^{56}\)
- “Place-holder” generation for use in modeling.

Only the net expected on-peak capacity is included in this line and does not include Energy Only.

Resources included in this category may be adjusted using a confidence factor (%), Line 16c, to reflect uncertainties associated with siting, project development or queue position.

Line 8a1 Wind Expected On-Peak
The amount of proposed wind capacity that is expected to be available on seasonal peak.

Line 8a2 – Wind Derate On-Peak
The amount of proposed wind capacity that is expected to be unavailable on seasonal peak.

\(^{56}\) Only provide generation from the queue that may be built within the assessment timeframe.

(i.e. LTRA = 10 Years )
Line 8a3 – Solar Expected On-Peak
The amount of proposed solar capacity that is expected to be available on seasonal peak.

Line 8a4 – Solar Derate On-Peak
The amount of proposed solar capacity that is expected to be unavailable on seasonal peak.

Line 8a5 – Hydro Expected On-Peak
The amount of proposed hydro capacity that is expected to be available on seasonal peak.

Line 8a6 – Hydro Derate On-Peak
The amount of proposed hydro capacity that is expected to be unavailable on seasonal peak.

Line 8a7 – Biomass Expected On-Peak
The amount of proposed biomass capacity that is expected to be available on seasonal peak.

Line 8a8 – Biomass Derate On-Peak
The amount of proposed biomass capacity that is expected to be unavailable on seasonal peak.

Line 8a9 – Energy Only
Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

Line 9 – Deliverable Internal Capacity = 6a+7a
Capacity counting towards the Deliverable Capacity Resource Margin. Existing, Certain plus Future, Planned Resources

Line 10 – Capacity Transactions - Imports = 10a+10b+10c+10d
The sum of all Firm, Non-firm, Expected and Provisional interregional purchases. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 10a – Firm
A firm contract has been signed and may be recallable. The total of these transactions will be associated with Existing, Certain Capacity. (Note: The sum of 10a1 and 10a2 may not add up to 10a, but must be <= 10a)

Line 10a1 – Full-Responsibility Purchases
Total of all purchases for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 10a – Firm.

Line 10a2 – Owned Capacity/Entitlement Located Outside the Region/Subregion
The amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10a – Firm.

Line 10b – Non-firm
A non-firm contract has been signed.
Line 10c – Expected
No contract executed, but in negotiation, projected, or other. The total of these transactions will be associated with Future, Planned Capacity Additions. (Note: The sum of 10c1 and 10c2 may not add up to 10c, but must be <= 10c)

Line 10c1 – Full-Responsibility Purchases
Total of all purchases for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 10c – Expected.

Line 10c2 – Owned Capacity/Entitlement Located Outside the Region/Subregion
The amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10c – Expected.

Line 10d – Provisional
Transactions under study, but negotiations have not begun. These transactions will be associated with Conceptual Capacity Additions.

Line 11 – Capacity Transactions - Exports = 11a+11b+11c+11d
The sum of all Firm, Non-firm, Expected and Provisional interregional sales. GUIDANCE: Be sure not to double count jointly-owned plants or generators.

Line 11a – Firm
A firm contract has been signed. The total of these transactions will be associated with Existing, Certain Capacity. (Note: The sum of 11a1 and 11a2 may not add up to 11a, but must be <= 11a)

Line 11a1 – Full-Responsibility Sales
Total of all sales for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 11a – Firm.

Line 11a2 – Owned Capacity/Entitlement Located Outside the Region/Subregion
The amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11a – Firm.

Line 11b – Non-firm
A non-firm contract has been signed and may be recallable.

Line 11c – Expected
No contract executed, but in negotiation, projected, or other. The total of these transactions will be associated with Future, Planned Capacity Additions. (Note: The sum of 11c1 and 11c2 may not add up to 11c, but must be <= 11c)
Line 11c1 – Full-Responsibility Sales
Total of all sales for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 11c – Expected.

Line 11c2 – Owned Capacity/Entitlement Located Outside the Region/Subregion
The amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11c – Expected.

Line 11d – Provisional
Transactions under study, but negotiations have not begun. These transactions will be associated with Conceptual Capacity Additions.

Line 12 – Existing, Certain & Net Firm Transactions = 6a+Net Firm Transactions

<table>
<thead>
<tr>
<th>Capacity Resources</th>
<th>Net Transactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing, Certain</td>
<td>Firm</td>
</tr>
</tbody>
</table>

Line 13 – Deliverable Capacity Resources = 12+7a+Net Expected Transactions

<table>
<thead>
<tr>
<th>Capacity Resources</th>
<th>Net Transactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing, Certain</td>
<td>Firm</td>
</tr>
<tr>
<td>Future, Planned</td>
<td>Expected</td>
</tr>
</tbody>
</table>

Line 14 – Prospective Capacity Resources = 13+6b-[Existing, Other Derates]+16b
A confidence factor adjusts Future, Other Resources in this line.

<table>
<thead>
<tr>
<th>Capacity Resources</th>
<th>Net Transactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing, Certain</td>
<td>Firm</td>
</tr>
<tr>
<td>Existing, Other (Reduced by All Derates)</td>
<td>Expected</td>
</tr>
<tr>
<td>Future, Planned</td>
<td></td>
</tr>
<tr>
<td>Future, Other (Adjusted)</td>
<td></td>
</tr>
</tbody>
</table>

Line 15 – Potential Capacity Resources = 13+6b-[Existing, Other Derates]+7b+8+Net Provisional Transactions

<table>
<thead>
<tr>
<th>Capacity Resources</th>
<th>Net Transactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing, Certain</td>
<td>Firm</td>
</tr>
<tr>
<td>Existing, Other (Reduced by All Derates)</td>
<td>Expected</td>
</tr>
<tr>
<td>Future, Planned</td>
<td>Provisional</td>
</tr>
<tr>
<td>Future, Other</td>
<td>Conceptual</td>
</tr>
</tbody>
</table>
Line 15a – Adjusted Potential Capacity Resources = 13+6b-[Existing, Other Derates]+16b+16d+Net Provisional Transactions
A confidence factor adjusts Future, Other and Conceptual Resources in this line.

<table>
<thead>
<tr>
<th>Capacity Resources</th>
<th>Net Transactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing, Certain Firm</td>
<td>Firm</td>
</tr>
<tr>
<td>Existing, Other (Reduced by All Derates)</td>
<td>Expected</td>
</tr>
<tr>
<td>Future, Planned Provisional</td>
<td>Provisional</td>
</tr>
<tr>
<td>Future, Other (Adjusted)</td>
<td></td>
</tr>
<tr>
<td>Conceptual (Adjusted)</td>
<td></td>
</tr>
</tbody>
</table>

Line 16a – Confidence of Future, Other Resources (7b), using reasonable judgement
Value must be between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). This value will correspond to the weight of emphasis placed on the Future, Other additions for the given year. If no adjustments are made by the Region/Subregion, 100(%) must be entered for this line.

Line 16b – Net Future, Other Resources After Confidence Percentage Is Applied = 7b*16
A calculated value factoring in the confidence of the net change in Future, Other Additions for the prior and given year.

Line 16c – Confidence of Conceptual Resources (8), using reasonable judgement
Value must be between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). This value will correspond to the weight of emphasis placed on the Conceptual additions for the given year.

Line 16d – Net Conceptual Resources After Confidence Percentage Is Applied = 8*16
A calculated value factoring in the confidence of the net change in Conceptual Additions for the prior and given year.

NOTE: Please provide both Capacity and Reserve Margins below.

Line 17C – Region/Subregion Target Capacity Margin
Value must be between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). The expected target margin for the Region/Subregion. If no value is entered, the NERC Reference Margin Level will be applied and it is assumed this value will remain constant throughout the timeframe of this assessment.

Line 17R – Region/Subregion Target Reserve Margin
Value must be between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). The expected target margin for the Region/Subregion. If no value is entered, the NERC Reference Margin Level will be applied and it is assumed this value will remain constant throughout the timeframe of this assessment.

CAPACITY MARGINS
Line 18C - Existing Certain and Net Firm Transactions = (12-3)/12
Line 19C - Deliverable Capacity Resources = (13-3)/13
Line 20C - Prospective Capacity Resources = (14-3)/14
Line 21C - Total Potential Resources = (15-3)/15
Line 22C - Adjusted Potential Resources = (15a-3)/15a

RESERVE MARGINS
Line 18R - Existing Certain and Net Firm Transactions = (12-3)/3
Line 19R - Prospective Capacity Resources = (13-3)/3
Line 20R - Prospective Capacity Resources = (14-3)/3
Line 21R - Total Potential Resources = (15-3)/3
Line 22R - Adjusted Potential Resources = (15a-3)/3

Note: The items below support the EIA-411 submittal.

Line 23 – Distributed Generator Capacity < 1 MW
Report the amount of capacity that comprises distributed generators that have less than 1 MW of capacity.

Line 24 – Other Capacity < 1 MW
Report the amount of capacity that does not comprise distributed generators.

Line 25 – Distributed Generator Capacity >= 1 MW
Report the amount of capacity that comprises distributed generators that have 1 MW of capacity or greater.

Line 26 – Capacity Total from EIA-860 (summed by NERC from EIA-860 data)
Report the total amount of seasonal capacity for all generators reported on Form EIA-860 Schedule 3, as provided by EIA. GUIDANCE: U.S. only, not needed for Canada or Mexico.

General Notes
Numeric values
All numbers should be entered as MW in whole, positive values – no decimals or negatives (subtractions will be done in form)

Actual Year Data
For the purposes of this form, “actual-year data” should be submitted based on the same principles as the planning-based projected data.
Do not include
- forced outages
- short-term transactions (purchases and sales)
- changes to capacity due to return-to-service or new-to-service delays
Schedule 4 – Capacity Imports, Exports and Incoming and Outgoing Transfers – Seasonal

Enter all actual and projected capacity purchases and sales (in megawatts) that involve entities outside of the Reporting Region or Subregion. The totals should agree with the totals in Schedule 3, Line 10, Purchases from Entities Outside the Region/Subregion and Line 11, Sales to Entities Outside the Region/Subregion.

Some data may be non-coincident due to differences in the month of the seasonal peaks for the purchaser and seller. An example would be a transfer that changes magnitude from July to August. The transfer would be reported in July by the selling party whose peak occurs in July and reported in August by the purchasing party whose peak occurs in August.

Please see Schedule 3 – Demand and Capacity section for more information on capacity physically located outside the regions’ boundaries.

Other Party EIA Code and Other Party Name
Enter the five character numeric code for that party. A list of the EIA company codes, by reporting party name, is available at the EIA website. If the name of the reporting party is not on this list, please enter the name of the party on the form and a code will be assigned by EIA.

Plant ID and Unit ID
Enter the EIA code for those unit specific purchases, sales, and transfers, if known.

Schedule 5 – Transmission Line Circuit Miles

Report only Existing (energized and in control of the operator) transmission lines as of 12/31/2008 in WHOLE number circuit miles for the specified voltages.

<table>
<thead>
<tr>
<th>Operative Voltage Range(kV)</th>
<th>Voltage Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-120</td>
<td>AC</td>
</tr>
<tr>
<td>121-150</td>
<td>AC</td>
</tr>
<tr>
<td>151-199</td>
<td>AC</td>
</tr>
<tr>
<td>200-299</td>
<td>AC, DC</td>
</tr>
<tr>
<td>300-399</td>
<td>AC, DC</td>
</tr>
<tr>
<td>400-599</td>
<td>AC, DC</td>
</tr>
<tr>
<td>600+</td>
<td>AC, DC</td>
</tr>
</tbody>
</table>

Schedule 6A – Projected Transmission Line Additions

This Schedule must be completed by each Regional Entity for all transmission line additions at 100kV and above projected for the ten-year period beginning with the year following the reporting year.
NOTE: This schedule is used to populate Schedule 5. Schedule 6 must be completed with ALL line additions.

Line A – Level of Certainty
Apply a level of certainty for each line addition based on the following criteria:

- **Under Construction**
  - Construction of the line has begun
- **Planned (any of the following)**
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement
- **Conceptual (any of the following)**
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
  - All other projected transmission lines should be categorized as “Conceptual”

Level of Certainty is used to populate Schedule 5 data.

Line B1 & B2 – Primary Driver(s)
Choose one or two of the predefined drivers for each line addition. While it is understood that one line could serve multiple functions (i.e. reliability and economics), please specify the principle consideration/driver for this addition.

- Reliability
- **Generation Integration (Choose one from below)**
  - Variable/Renewable Integration
  - Nuclear Integration
  - Fossil-Fire Integration
  - Hydro Integration
- Economics or Congestion
- Other

Line C – Tie Line?
Please specify whether this addition is a tie line across two or more Regions. Default = No

Line 1 – Terminal From Location
Enter the name of the beginning terminal point of the line.

Line 2 – Terminal To Location
Enter the name of the ending terminal point of the line.

Line 3 – Company Name
Enter the company name.
Line 4 – EIA Company Code
Identify each organization by the six-character code assigned by EIA.

Line 5 – Type of Organization
Identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).

Line 6 – Percent Ownership
If the transmission line will be jointly-owned, enter the percentages owned by each individual respondent.

Line 7 – Line Length
Enter miles between beginning and ending terminal points of the line, regardless of the number of conductors or circuits carried.
Line Length is used to populate Schedule 5.

Line 8 – Line Type
Select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).

Line 9 – Voltage Type
Select voltage as alternating current (AC) or direct current (DC).

Line 10 – Voltage Operating
Enter the voltage at which the line is normally operated in kilovolts (kV).
Operating Voltage is used to populate Schedule 5. A non-predefined voltage entry will not be populated in Schedule 5.

<table>
<thead>
<tr>
<th>Operating Voltage Range(kV)</th>
<th>Voltage Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-120</td>
<td>AC</td>
</tr>
<tr>
<td>121-150</td>
<td>AC</td>
</tr>
<tr>
<td>151-199</td>
<td>AC</td>
</tr>
<tr>
<td>200-299</td>
<td>AC DC</td>
</tr>
<tr>
<td>300-399</td>
<td>AC DC</td>
</tr>
<tr>
<td>400-599</td>
<td>AC DC</td>
</tr>
<tr>
<td>600+</td>
<td>AC DC</td>
</tr>
</tbody>
</table>

Line 11 – Voltage Design
Enter the voltage at which the line was designed to operate in kilovolts (kV).

Line 12 – Conductor Size
Enter the size of the line conductor in thousands of circular mils (MCM).

Line 13 – Conductor Material Type
Enter the line conductor material type – aluminum, ACCR, ACSR, copper, or other.
**Line 14 – Bundling Arrangement**
Enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other.

**Line 15 – Circuits per Structure Present**
Enter the current number of three-phase circuits on the structures of the line.

**Line 16 – Circuits per Structure Ultimate**
Enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.

**Line 17 – Pole/Tower Type**
Identify the predominant pole/tower material for the line – wood, concrete, steel, combination, composite material, or other. Also include the type of structure – single pole, H-frame structure, tower, underground, or other.

**Line 18 – Capacity Rating**
Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).

**Line 19 – Projected In-Service Month (MM)**
Enter the projected month the line will be energized under the control of the system operator.

**Line 20 – Projected In-Service Year (YYYY)**
Enter the projected year the line will be energized under the control of the system operator. Projected In-Service Year is used to populate Schedule 5.

**Schedule 6B – Projected Transformer Additions**

This Schedule must be completed by each Regional Entity for all transformer additions at 200 kV Low-Side and above projected for the ten-year period beginning with the year following the reporting year. Replacement transformers should be reported and noted in the Description/Status field.

**Line 1 – Transformer Project Name**
Enter the name of the project.

**Line 2 – High-Side Voltage (kV)**
Enter High-Side Voltage.

**Line 3 – Low-Side Voltage (kV)**
Enter Low-Side Voltage.

**Line 4 – Expected In-Service Date (MM/YYYY)**
Enter the projected date the transformer will be energized under the control of the system operator.

**Line 5 – Description/Status**
Provide a brief description/status on the projected transformer addition.
Schedule 7 – Annual Data on Transmission Line Outages for EHV Lines (Voluntary)

In general terms, an Outage is defined as the removal from service availability of a generation unit, transmission line, or other facility for either scheduled (planned) or unscheduled (unplanned) reasons. For this reporting purpose, individual outage duration should be reported following similar company standards and/or regional reliability guidelines. The outage durations reported on the Form EIA-411 represent the annual summation (in hours) of all these events for the reporting NERC region.

The duration of an outage is the amount of time that the transmission line was completely de-energized. For preferred reporting practices, do not start recording duration until the line is completely deenergized and stop recording duration when the entire line is reenergized. If practices differ, please footnote.

Outages that occur on intertie lines between regions are to be reported only once by one or the other of the reporting regions.

Scheduled Outages

Information collected on scheduled outages is for the events where the duration was 1 hour or more in length. This includes line upgrades and the normal maintenance that is usually performed during non-peak load periods. Each time a line is removed from service, this is recorded as one scheduled outage (this includes accounting for periods where lines are returned to service on a periodic basis during a previously scheduled work period).

Unscheduled Outages

The information requested on unscheduled outages covers all events in which a line is automatically removed from service by system protection, or must be removed from service due to unforeseen circumstances. The unscheduled outage of any circuit continues until that circuit is restored to service. If company practices are different from this, please footnote.

- For any set of outages that have more than one cause, please report the initial cause (i.e., the cause that occurred first).
- For an outage of a circuit to be considered, the line(s) must be deenergized. If the line recloses and trips again within a minute of the initial outage, it is only considered one outage. The line would need to remain in service for longer than one minute between the breaker operations to be considered as two outages.
- ‘Failed tests’ are not considered additional outages. If the operator or dispatcher tries to energize a circuit that has a fault on it, and it immediately re-opens, this is considered a ‘failed test’ and is not an additional outage. However if the test ‘passed’ and the line remained in service for longer than one minute, any additional outages will be recorded as a new outage.
- Removal of any transmission line (including radials) from service is considered as an outage. However, transmission lines that are removed for system stability (such as ‘voltage control’) should not be reported as an outage. These maybe reported separately as a footnote.
When a tap off a transmission line is removed from service (scheduled or unscheduled outage) and the transmission line itself remains energized only the tap is considered out-of-service.

All transmission line outages involving Extra High Voltage (EHV) A.C. lines of 230 kV and above are to be aggregated by each Regional Council and reported on this schedule.

Line 1 – Applicable Voltage Class
If you are reporting an outage(s) of a voltage class that is not listed, identify the voltage class in the column labeled ‘Other (specify)’.

Line 2 – Number of Scheduled Outages
Report the total number of scheduled outages that occurred in the reporting period for each voltage class.

Line 3 – Number of Circuits Involved
Report the total number of “circuit outages”, that occurred during the reporting period, for all scheduled outages. For example, if there was one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there is another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.

Line 4 – Scheduled Circuit-Hours Out of Service
Report the total scheduled circuit-hours out of service for all of the scheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for scheduled reasons during the reporting period.

Line 5 – Number of Non-Momentary Unscheduled Outages
Report the number of non-momentary (lasting sixty seconds or longer) unscheduled outages that occurred during the reporting period for each voltage class.

Line 6 – Number of Circuits Involved
Report the total number of “circuit outages”, that occurred during the reporting period, for all unscheduled outages, both momentary and non-momentary. For example, if there is one outage and five circuits are involved, the respondent should report 5 circuit outages. Alternatively, if there was one outage with two circuits involved and subsequently there was another outage with four circuits involved, the respondent should report 6 circuit outages, for each voltage class.

Line 7 – Unscheduled Circuit-Hours Out of Service
Report the unscheduled circuit-hours out of service for all of the unscheduled outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was out of service for unscheduled reasons during the reporting period.

Line 8 – Weather
Includes all unscheduled outages caused by severe weather conditions (tornado, hurricane, lightning strikes, ice, high winds, etc.) that are the primary cause of the outage.
Line 9 – Animals, Fire and Smoke, Human Accidents
Includes the events caused by actions where animal movement or nesting impacts electrical operations of equipment or facilities. Actions by humans (accidents or intention) that not employed or under contract by the utility in the responsible area that impact operations will be reported. Fire and conditions linked to this from whatever event that started the fire/smoke conditions need to be accounted for in this category.

Line 10 – Vegetation
Includes outages initiated by vegetation in the proximity of transmission facilities. Reporting definition will be consistent with the NERC template and vegetation management criteria.

Line 11 – Operator Action
Includes any action traceable to employees and/or contactors for companies operating, maintaining, and/or providing assistance for actions that impacted any part of the operations of the Nation’s power grids will be identified and reported in this category. Also, any failure or interpretation of standard industry practices and guidelines that cause an outage event will be reported in this category.

Line 12 – Equipment Failure
Includes failure of any line or terminal equipment.

Line 13 – Unknown
Any unknown sources should be reported in this category.

Line 14 – Other (Calculated automatically by the spreadsheet)
Includes all other causes, computed automatically to be the difference between 100% and the sum of Lines 8 through 13.

Schedule 9 – Fuel-Type Breakdown – Seasonal
Provide Fuel-Type Breakdowns for each Supply Category:

PART I – Existing, Certain Resources
Enter the seasonal actual and projected amounts of capacity for each fuel-type based upon Existing, Certain Resources (Lines 6a from Schedule 3 – Demand and Capacity – Seasonal).

PART II – Future, Planned Resources
Enter the seasonal actual and projected amounts of capacity for each fuel-type based upon Future, Planned Resources (Line 7a from Schedule 3 – Demand and Capacity – Seasonal).

PART III – Conceptual Resources
Enter the seasonal actual and projected amounts of capacity for each fuel-type based upon Conceptual Resources (Line 8 from Schedule 3 – Demand and Capacity – Seasonal)
<table>
<thead>
<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adequacy</td>
<td></td>
<td>The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.</td>
</tr>
<tr>
<td>Adjacent Balancing Authority</td>
<td></td>
<td>A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.</td>
</tr>
<tr>
<td>Adverse Reliability Impact</td>
<td></td>
<td>The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.</td>
</tr>
<tr>
<td>Agreement</td>
<td></td>
<td>A contract or arrangement, either written or verbal and sometimes enforceable by law.</td>
</tr>
<tr>
<td>Ancillary Service</td>
<td></td>
<td>Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (From FERC order 888-A.)</td>
</tr>
<tr>
<td>Area Control Error</td>
<td>ACE</td>
<td>The instantaneous difference between a Balancing Authority’s net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.</td>
</tr>
<tr>
<td>Automatic Generation Control</td>
<td>AGC</td>
<td>Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.</td>
</tr>
<tr>
<td>Available Transfer Capability</td>
<td>ATC</td>
<td>A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.</td>
</tr>
<tr>
<td>Balancing Authority</td>
<td>BA</td>
<td>The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.</td>
</tr>
<tr>
<td>Term</td>
<td>Acronym</td>
<td>Definition</td>
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</tr>
<tr>
<td>Balancing Authority Area</td>
<td></td>
<td>The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.</td>
</tr>
<tr>
<td>Base Load</td>
<td></td>
<td>The minimum amount of electric power delivered or required over a given period at a constant rate.</td>
</tr>
<tr>
<td>Bulk Electric System</td>
<td>BES</td>
<td>As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.</td>
</tr>
<tr>
<td>Burden</td>
<td></td>
<td>Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.</td>
</tr>
<tr>
<td>Capacity Benefit Margin</td>
<td>CBM</td>
<td>The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.</td>
</tr>
<tr>
<td>Capacity Emergency</td>
<td></td>
<td>A capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.</td>
</tr>
<tr>
<td>Cascading</td>
<td></td>
<td>The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.</td>
</tr>
<tr>
<td>Cogeneration</td>
<td></td>
<td>Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.</td>
</tr>
<tr>
<td>Compliance Monitor</td>
<td></td>
<td>The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.</td>
</tr>
<tr>
<td>Term</td>
<td>Acronym</td>
<td>Definition</td>
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</tr>
<tr>
<td>Congestion Management Report</td>
<td></td>
<td>A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.</td>
</tr>
<tr>
<td>Constrained Facility</td>
<td></td>
<td>A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.</td>
</tr>
<tr>
<td>Contingency</td>
<td></td>
<td>The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.</td>
</tr>
<tr>
<td>Contingency Reserve</td>
<td></td>
<td>The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.</td>
</tr>
<tr>
<td>Critical Assets</td>
<td></td>
<td>Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.</td>
</tr>
<tr>
<td>Critical Cyber Assets</td>
<td></td>
<td>Cyber Assets essential to the reliable operation of Critical Assets.</td>
</tr>
<tr>
<td>Curtailment</td>
<td></td>
<td>A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.</td>
</tr>
<tr>
<td>Cyber Assets</td>
<td></td>
<td>Programmable electronic devices and communication networks including hardware, software, and data.</td>
</tr>
<tr>
<td>Cyber Security Incident</td>
<td></td>
<td>Any malicious act or suspicious event that:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.</td>
</tr>
<tr>
<td>Demand</td>
<td></td>
<td>1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. The rate at which energy is being used by the customer.</td>
</tr>
<tr>
<td>Demand-Side Management</td>
<td>DSM</td>
<td>The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.</td>
</tr>
<tr>
<td>Term</td>
<td>Acronym</td>
<td>Definition</td>
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</tr>
<tr>
<td>Direct Control Load Management</td>
<td>DCLM</td>
<td>Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.</td>
</tr>
<tr>
<td>Distribution Provider</td>
<td></td>
<td>Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.</td>
</tr>
</tbody>
</table>
| Disturbance                              |         | 1. An unplanned event that produces an abnormal system condition.  
2. Any perturbation to the electric system.  
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. |
<p>| Economic Dispatch                         |         | The allocation of demand to individual generating units on line to effect the most economical production of electricity. |
| Electrical Energy                         |         | The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh). |
| Element                                   |         | Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. |
| Emergency or BES Emergency               |         | Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. |
| Emergency Rating                          |         | The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. |
| Energy Emergency                         |         | A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers’ expected energy requirements. |</p>
<table>
<thead>
<tr>
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<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Rating</td>
<td></td>
<td>The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.</td>
</tr>
<tr>
<td>Facility</td>
<td></td>
<td>A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)</td>
</tr>
<tr>
<td>Facility Rating</td>
<td></td>
<td>The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.</td>
</tr>
<tr>
<td>Firm Demand</td>
<td></td>
<td>That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.</td>
</tr>
<tr>
<td>Firm Transmission Service</td>
<td></td>
<td>The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.</td>
</tr>
<tr>
<td>Forced Outage</td>
<td></td>
<td>1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2. The condition in which the equipment is unavailable due to unanticipated failure.</td>
</tr>
<tr>
<td>Frequency Bias</td>
<td></td>
<td>A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area’s response to Interconnection frequency error.</td>
</tr>
<tr>
<td>Frequency Bias Setting</td>
<td></td>
<td>A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.</td>
</tr>
<tr>
<td>Frequency Deviation</td>
<td></td>
<td>A change in Interconnection frequency.</td>
</tr>
<tr>
<td>Frequency Error</td>
<td></td>
<td>The difference between the actual and scheduled frequency. (F_A – F_S)</td>
</tr>
<tr>
<td>Generator Operator</td>
<td></td>
<td>The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.</td>
</tr>
<tr>
<td>Generator Owner</td>
<td></td>
<td>Entity that owns and maintains generating units.</td>
</tr>
<tr>
<td><strong>Term</strong></td>
<td><strong>Acronym</strong></td>
<td><strong>Definition</strong></td>
</tr>
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<td>-------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| Host Balancing Authority                |             | 1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority’s metered boundaries.  
<pre><code>                                       |             | 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located. |
</code></pre>
<p>| Independent Power Producer              | IPP         | Any entity that owns or operates an electricity generating facility that is not included in an electric utility’s rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity. |
| Institute of Electrical and Electronics Engineers, Inc. | IEEE       |                                                                               |
| Interchange Distribution Calculator     | IDC         | The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection. |
| Interchange                             |             | Energy transfers that cross Balancing Authority boundaries.                   |
| Interchange Authority                   |             | The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes. |
| Interchange Schedule                    |             | An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. |
| Interchange Transaction                 |             | An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries. |
| Interconnected Operations Service       |             | A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems. |
| Interconnection                         |             | When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT. |
| Interconnection Reliability Operating Limit | IROL     | A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System. |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection Reliability Operating Limit ( T_v )</td>
<td>IROL ( T_v )</td>
<td>The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit’s ( T_v ) shall be less than or equal to 30 minutes.</td>
</tr>
<tr>
<td>Intermediate Balancing Authority</td>
<td></td>
<td>A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.</td>
</tr>
<tr>
<td>Interruptible Load or Interruptible Demand</td>
<td></td>
<td>Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.</td>
</tr>
<tr>
<td>Joint Control</td>
<td></td>
<td>Automatic Generation Control of jointly owned units by two or more Balancing Authorities.</td>
</tr>
<tr>
<td>Load</td>
<td></td>
<td>An end-use device or customer that receives power from the electric system.</td>
</tr>
<tr>
<td>Load Shift Factor</td>
<td>LSF</td>
<td>A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.</td>
</tr>
<tr>
<td>Load-Serving Entity</td>
<td></td>
<td>Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.</td>
</tr>
</tbody>
</table>
| Misoperation                                         |         | • Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.  
  • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).  
  • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity. |
<p>| Native Load                                          |         | The end-use customers that the Load-Serving Entity is obligated to serve.                                                               |
| Net Actual Interchange                               |         | The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.           |</p>
<table>
<thead>
<tr>
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<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Energy for Load</td>
<td></td>
<td>Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.</td>
</tr>
<tr>
<td>Net Interchange Schedule</td>
<td></td>
<td>The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.</td>
</tr>
<tr>
<td>Net Scheduled Interchange</td>
<td></td>
<td>The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.</td>
</tr>
<tr>
<td>Non-Firm Transmission Service</td>
<td></td>
<td>Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.</td>
</tr>
</tbody>
</table>
| Non-Spinning Reserve                     |         | 1. That generating reserve not connected to the system but capable of serving demand within a specified time.  
2. Interruptible load that can be removed from the system in a specified time.                                                                                                                                                                                                                                                                                                                                 |
<p>| Normal Clearing                           |         | A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.                                                                                                                                                                                                                                                                                                               |
| Normal Rating                             |         | The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.                                                                                                                                                                                                                                                        |
| Off-Peak                                  |         | Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.                                                                                                                                                                                                                                                                                                                             |
| On-Peak                                   |         | Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.                                                                                                                                                                                                                                                                                                                               |
| Open Access Same Time Information Service | OASIS   | An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.                                                                                                                                                                                                                                                                                               |
| Open Access Transmission Tariff           | OATT    | Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.                                                                                                                                                                                                                                           |</p>
<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Operating Plan</td>
<td></td>
<td>A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.</td>
</tr>
<tr>
<td>Operating Procedure</td>
<td></td>
<td>A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.</td>
</tr>
<tr>
<td>Operating Process</td>
<td></td>
<td>A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.</td>
</tr>
<tr>
<td>Operating Reserve</td>
<td></td>
<td>That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.</td>
</tr>
<tr>
<td>Operating Reserve – Spinning</td>
<td></td>
<td>The portion of Operating Reserve consisting of:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</td>
</tr>
<tr>
<td>Operating Reserve – Supplemental</td>
<td></td>
<td>The portion of Operating Reserve consisting of:</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</td>
</tr>
<tr>
<td>Term</td>
<td>Acronym</td>
<td>Definition</td>
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<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Operating Voltage</td>
<td></td>
<td>The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.</td>
</tr>
</tbody>
</table>
| Peak Demand                  |         | 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).  
2. The highest instantaneous demand within the Balancing Authority Area.                                                                                                                                  |
| Planning Authority           |         | The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.                                                                                                                                                                                                                   |
| Pro Forma Tariff             |         | Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.                                                                                                                                                                                                   |
| Purchasing-Selling Entity    |         | The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.                                                                                                           |
| Ramp Rate or Ramp            |         | (Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.  
(Generator) The rate, expressed in megawatts per minute, that a generator changes its output.                                                                                                              |
<p>| Rating                       |         | The operational limits of a transmission system element under a set of specified conditions.                                                                                                                                                                                                                                                        |
| Reactive Power               |         | The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar). |
| Real Power                   |         | The portion of electricity that supplies energy to the load.                                                                                                                                                                                                                                                                                   |
| Receiving Balancing Authority|         | The Balancing Authority importing the Interchange.                                                                                                                                                                                                                                                                                             |</p>
<table>
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<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
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</table>
| Regional Reliability          |         | Organization 1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.  
<p>|                               |         | 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.    |
| Regional Reliability Plan     |         | The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished. |
| Regulating Reserve            |         | An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.                   |
| Regulation Service           |         | The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service. |
| Reliability Coordinator       |         | The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision. |
| Reliability Coordinator Area  |         | The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas. |
| Reportable Disturbance        |         | Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance. |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reserve Sharing Group</td>
<td></td>
<td>A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.</td>
</tr>
<tr>
<td>Resource Planner</td>
<td></td>
<td>The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.</td>
</tr>
<tr>
<td>Response Rate</td>
<td></td>
<td>The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).</td>
</tr>
<tr>
<td>Right-of-Way (ROW)</td>
<td></td>
<td>A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.</td>
</tr>
<tr>
<td>Scenario</td>
<td></td>
<td>Possible event.</td>
</tr>
<tr>
<td>Schedule</td>
<td></td>
<td>(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.</td>
</tr>
<tr>
<td>Scheduling Path</td>
<td></td>
<td>The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.</td>
</tr>
<tr>
<td>Special Protection System (Remedial Action Scheme)</td>
<td></td>
<td>An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.</td>
</tr>
<tr>
<td>Spinning Reserve</td>
<td></td>
<td>Unloaded generation that is synchronized and ready to serve additional demand.</td>
</tr>
<tr>
<td>Stability</td>
<td></td>
<td>The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.</td>
</tr>
<tr>
<td>Term</td>
<td>Acronym</td>
<td>Definition</td>
</tr>
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</tr>
<tr>
<td>Stability Limit</td>
<td></td>
<td>The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.</td>
</tr>
<tr>
<td>Sustained Outage</td>
<td></td>
<td>The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.</td>
</tr>
<tr>
<td>System</td>
<td></td>
<td>A combination of generation, transmission, and distribution components.</td>
</tr>
</tbody>
</table>
| System Operating Limit       |         | The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:  
  - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)  
  - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)  
  - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)  
  - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits) |
| System Operator              |         | An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.                                                                                                                                    |
| Telemetering                 |         | The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.                                                                                       |
| Tie Line                     |         | A circuit connecting two Balancing Authority Areas.                                                                                                                                                                                                                                                                                     |
| Tie Line Bias                |         | A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.                                                                                                                                                                       |
| TLR Log                      |         | Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site. |

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<table>
<thead>
<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Transfer Capability</td>
<td>TTC</td>
<td>The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.</td>
</tr>
<tr>
<td>Transaction</td>
<td></td>
<td>See Interchange Transaction.</td>
</tr>
<tr>
<td>Transfer Capability</td>
<td></td>
<td>The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from “Area A” to “Area B” is not generally equal to the transfer capability from “Area B” to “Area A.”</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
<td>An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.</td>
</tr>
<tr>
<td>Transmission Constraint</td>
<td></td>
<td>A limitation on one or more transmission elements that may be reached during normal or contingency system operations.</td>
</tr>
</tbody>
</table>
| Transmission Customer       |         | 1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service.  
2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.                                                                                                                                                                                                 |
<p>| Transmission Line           |         | A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.                                                                 |
| Transmission Operator       |         | The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.                                                                                                                                                                                        |
| Transmission Owner          |         | The entity that owns and maintains transmission facilities.                                                                                                                                                                                                                                                                             |
| Transmission Planner        |         | The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.                                                                                                                                  |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Reliability Margin</td>
<td>TRM</td>
<td>The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.</td>
</tr>
<tr>
<td>Transmission Service</td>
<td></td>
<td>Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.</td>
</tr>
<tr>
<td>Transmission Service Provider</td>
<td></td>
<td>The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.</td>
</tr>
<tr>
<td>Wide Area</td>
<td></td>
<td>The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.</td>
</tr>
</tbody>
</table>
Appendix I: Resource Adequacy Methods

Survey for Inventory of NERC Regional Resource Adequacy Assessment Criteria by Regional Reliability Organization\(^5\)

Probabilistic Methods

The comparability of these assessments is somewhat impeded because of the lack of uniformity in assessment metric definitions and methods. However, in almost all cases, the objective is to test whether existing and future resources are sufficient to assure an LOLE of no more than 1 day in 10 years where all relevant factors and uncertainties are included in the simulation. Therefore, despite the differences in definitions and methods, the goal is that the resulting levels of adequacy be similar.

1. **Stochastic Parameters**: The model used to assess resource adequacy should take into account all relevant factors and uncertainties and include them in the simulation. Practically speaking this can be done by representing certain parameters, which embody much of the “risk” that there may be insufficient resources to meet load, as stochastic parameters. 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) or discrete histories on the forced outage attributes of thermal generation.

The RIS survey indicated that, in all cases, forced outages of thermal generators is one of the universal stochastic parameters in probabilistic assessments. In almost all cases, load uncertainty, i.e. load uncertainty due to adverse temperatures, is another stochastic parameter. In FRCC, which does not include load uncertainty as a stochastic parameter, load uncertainty is modeled using scenario analyses. If load uncertainty due to load growth uncertainty is modeled, it is generally analyzed using scenario analyses. In areas, with an abundance of wind or hydro resources (especially if the resource is storage-limited), wind and/or hydro generation may also be modeled as stochastic parameters 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.

Unless weighting factors are specified for scenario analyses, the implicit assumption is that all scenarios have equal probability of occurrence. Developing a decision metric based on multiple scenarios allows subjective weighting of the

\(^5\) The complete Survey for Inventory of NERC Regional Resource Adequacy Assessment Criteria by Regional Reliability Organization can be found at [http://www.nerc.com/docs/pc/ris/RRO_Adequacy_Assessment_Practices-Survey_Responses_08_14_08.xls](http://www.nerc.com/docs/pc/ris/RRO_Adequacy_Assessment_Practices-Survey_Responses_08_14_08.xls)
2. Probabilistic Methods: There are two primary methods to model uncertainty in the probabilistic simulation tools whereby two probability distributions are “added” or “subtracted” to or from each other to get a combined risk distribution. Convolution is the mathematical technique whereby selected probability distributions are combined. In resource adequacy assessments, a probability distribution of the availability of generation capacity is combined with a probability distribution of customer loads to quantify how often loads would exceed available resources.

a. Monte Carlo Convolution: The second method is an analytic convolution, which means that all of the probability distributions of load are expressed in the form of mathematical equations and mathematically combined. The result of this type of convolution is a modified mathematical function, representing a distribution which can be converted to a probabilistic reliability metric. Because of the complexities of the mathematics, many of the constraints in a large integrated power system cannot be explicitly included in the models.

b. Analytic Convolution: The second method is through analytic convolution, which means that all of the probability distributions of load are expressed in the form of mathematical equations and mathematically combined. The result of this type of convolution is a modified mathematical, represented, distribution which can be converted to a probabilistic reliability metric. Because of the complexities of the mathematics, many of the constraints in a large integrated power system cannot be explicitly included in the models.

3. Definition of a Loss of Load (LOL) Occurrence: There are a number of definitions regarding what constitutes a Loss of Load Occurrence in a probabilistic assessment. The LOL occurrence definition indicates a single instance in the ability to serve firm load, which if it occurs more than a certain threshold (e.g., 1 day in 10 years) indicates the need to construct resources or institute demand-side management programs to assure that the accepted level of reliability is maintained.

a. Inability to Meet Firm Load: Using this definition of a LOL occurrence, the region, or subregion, would use all available capacity including operating reserves to serve firm load. If in any hour, or whatever time frame constitutes an “LOL occurrence”, load exceeds available capacity, then this is defined as an “LOL occurrence.” Based on feedback solicited subsequent to the RIS survey, it appears almost all regions use this definition of an LOL occurrence.

b. Inability to Meet Firm Load plus Operating Reserves, or a Portion Thereof: Using this definition of an LOL occurrence the region, or subregion, would use all available capacity to meet firm load and operating reserves, or perhaps just the spinning component of operating reserves. An “LOL occurrence” would be defined as the inability to meet load plus
operating reserves, or a component thereof. ERCOT uses this definition of an LOL occurrence.

c. **Inability to Meet Firm Load plus Operating Reserves Above a Certain Threshold:** The Pacific Northwest (PNW) sub-area of WECC only counts LOL occurrence as an energy or capacity curtailment that exceeds a minimum threshold. The reason for setting a deterministic threshold in the analysis is to compensate for some minimum amount of operational flexibility that cannot be, or is not, represented in the reliability modeling to assure that the model calculated customer curtailment is a true LOL occurrence. Since the model is unable to simulate the full flexibility of the hydro system, which supplies 75% of the sub-area’s load in a normal water year, to deal with thermal generator outages, cold snap or heat wave events; stakeholders have determined a reasonable minimum threshold level above which a curtailment is considered a “LOL occurrence”. In this framework, there are two types of LOL Occurrences:

1. An energy “LOL occurrence” is defined as the inability to meet firm energy load, expressed as a percent of total firm energy load, over a season, or over a year.

2. A capacity “LOL occurrence” is defined as the inability to meet firm load plus operating reserves less an allowance for unmodeled flexibility in the hydro system in a single hour.

4. **Probabilistic Metrics:**

   a. **LOLP:** Loss of Load Probability [LOLP] is the building block of probabilistic analyses. LOLP is typically defined as the probability of firm load demand not being met in any given time period. In some areas, the determination is whether firm load demand plus operating reserves, or a portion thereof, can be met in a given time period. When the probabilities of events are summed over time, the result is an expectation.

   b. **LOLE:** Loss of Load Expectation is defined as the sum of LOLP values over time. For example, if a system was always short of capacity, in every hour in a year, with no chance of having enough capacity, the LOLE would be 8760 Loss of Load Hours per year or 365 Loss of Load Days per year, or 260 Loss of Load Weekdays per year.

   For a Monte Carlo based LOLE evaluation, many simulations are required for probabilistic assessments to develop a statistically significant reliability index. Thus, a system that exactly satisfies the metric of an LOLE of 1 day in 10 years might be a system that experiences misses in 100 days out of a 1000 simulation years in a 10-year horizon (100 days per 1000 simulated years or 0.1 days per simulated year). For quantifying reliability and determining the required reserves necessary to meet the 1 day in 10 years LOLE, many planning authorities use a reliability model. For example, a typical model compares the available capacity resources against loads using statistical

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58 NPCC including NYISO, ISO-NE, etc. This is also the PJM definition, which includes the Midwest PRSG.

59 ERCOT
techniques and determines the annual LOLE. The LOLE is calculated for every period of the year and accumulated through the year. Some of the periods used in this analysis include peak hour for 260 days, i.e. all days per year excluding weekends, peak hour for 365 days, or even every hour of the year. When the LOLE for all of the periods have been determined and summed for the year, the system is considered to be in compliance with the annual resource planning reliability criterion if the cumulative LOLE is lower than, or equal to, 1 day in 10 years on an annual basis (or 0.1 days per year).

In ERCOT, LOLE stands for a loss of load event and is described as any single hour or group of consecutive hours where load exceeds available resources. For example, 1 hour alone of unserved energy constitutes a LOLE just as 5 consecutive hours of unserved energy constitutes an LOLE. Results are given as average Loss of Load Events in ten years.

In ERCOT, LOLE stands for a loss of load event and is described as any single hour or group of consecutive hours where load exceeds available resources. For example, 1 hour alone of unserved energy constitutes a LOLE just as 5 consecutive hours of unserved energy constitutes an LOLE. Results are given as average Loss of Load Events in ten years.

The PNW currently defines LOLE as the probability of a certain energy load not being met over a certain timeframe. Their LOLE target is 5%, which means that no more than five percent of the simulations (or games) include curtailment events exceeding the minimum threshold. The PNW is currently discussing a change to their methodology to align their probabilistic assessments better with those in the rest of the NERC regions and subregions.

c. **EUE**: Expected Unserved Energy [EUE] is typically synonymous with Energy Not Served [ENS], measured in MWh, across all iterations of the stochastic simulation. Results are given as average MWh of EUE in ten years. The EUE index is similar to the LOLH index except that the MW shortage in each period is weighted by the probability.

d. **LOLH**: Loss of Load Hours is the hourly counterpart to the daily LOLE calculation but the calculation is based on the summation of the probabilities for all hours in a year.

5. **Impact of Size of Footprint on LOLE and Margin Analysis**:

The LOLE analysis is influenced by the size of the area over which the analysis is performed. The larger the system, the lower the reserve margin needed to achieve an LOLE of 0.1 day per year because of factors such as load diversity and the availability of additional generation to meet low probability contingencies (assuming adequate transmission). Interconnected areas will have a lower LOLE than that of an individual area, which is not interconnected with another area.

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60 The NWPCC defines LOLP as the probability that an energy or capacity “miss” will occur over the winter season, or over the year.

61 ERCOT
One of the key assumptions in many LOLE calculations is that transmission is infinite to move capacity and energy from where it is located to where it is needed. Certain models can take into consideration some amount of transmission limitation. However, as system size becomes larger, the validity of this assumption becomes more questionable. Transmission interfaces are typically influenced by the state of the system and the interface limits are most often developed based on the worst single contingency with all lines in service. The validity of the all lines in service assumption, and the implication of this assumption for large footprint reliability studies is a topic of a future RIS effort.

Pursuant to a Planning Committee motion at the December 2008 meeting, the Planning Committee’s Executive Committee has approved the G&T Reliability Planning Models Task Force and scope. This task force will evaluate approaches for composite generation and transmission reliability modeling for the purpose of forecasting G&T reliability. The task force will provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC’s long-term reliability assessments.

A final report will be presented to the Planning Committee with recommendations on whether NERC should proceed with composite generation and transmission reliability modeling and if so, how it should proceed. The final report should include the following:

- An evaluation of methodologies for computing composite reliability
- An evaluation of available software
- If composite reliability modeling is recommended to proceed:
  - Identification of data requirements and how they would be collected.
  - Identification of possible metrics and how they would be used
  - Recommendations on the release of results and the underlying assumptions and data
  - A work plan and budget

**Deterministic Approaches and Methods:**

The RIS survey indicates that only one Region, WECC, uses deterministic methods to develop resource adequacy targets. WECC uses a “building block” approach to cover operating reserves, additional reserves needed to cover prolonged forced outages as well as reserves needed to cover severe weather contingencies. WECC’s planning reserve margins are specified by sub-area for both summer and winter.

Two of the sub-areas within WECC have specified resource adequacy targets, California and the Pacific Northwest (PNW). The WECC targets are not significantly different for California. However, the PNW reserve margin targets of 23 and 24% for winter and summer, respectively, which are derived from an LOLP analysis, are considerably higher than the WECC targets. The PNW targets, however, cannot be compared directly to the WECC targets because the peak-load duration period for the PNW is not a single hour. Because of the particular characteristics of the hydroelectric system, which provides about 75% of the PNW electricity on average, the critical peak-load duration occurs over an 18 hour sustained period (6 highest load hours over 3 consecutive days).

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62 More information on the GTRPMTF is available at: [http://www.nerc.com/filez/gtrpmtf.html]
Appendix II: Committee & Staff Organization Charts

The following organizational Charts reflect the Board of Trustees, NERC Staff, NERC Committee’s and their Subcommittees responsible for reliability assessment.

NERC Organizational Chart
March 20, 2007

Board of Trustees

- President and CEO
- NERC Staff

- Compliance Committee
- Corporate Governance and Human Resources Committee
- Finance and Audit Committee
- Nominating Committee
- Technology Committee

Member Representatives Committee

Compliance and Certification Committee
Critical Infrastructure Protection Committee
Operating Committee
Personnel Certification Governance Committee
Planning Committee
Standards Committee