THE NARRAGANSETT ELECTRIC COMPANY

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Testimony of

Melissa Scott, P.E.

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PREFILED TESTIMONY OF MELISSA SCOTT, P.E.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Melissa Scott. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q. By whom are you employed and in what position?

A. I am employed as a Lead Senior Engineer by New England Power Company in the Transmission Network Planning and Development Department.

Q. What are your responsibilities in that position?

A. I am responsible for transmission system planning for National Grid in its New England and New York service territory. Transmission System Planning includes determination of need for reinforcement of the transmission supply system, evaluation of alternative solutions, and selection of the most satisfactory solution.

Q. Please describe your education, training and experience.

A. I am a graduate of University of Vermont, holding a Bachelor of Science degree in Electrical Engineering; I am also a graduate of Rensselaer Polytechnic Institute, holding a Master of Engineering degree in Electric Power Engineering. I have over ten years of experience in power system planning and analysis. I have been a Lead Senior Engineer in the Transmission Network Planning and Development department since April of 2002; prior to that I was a Senior Engineer in the department since September of 2000. During this time, I have been responsible for many transmission planning studies including the study of our Southern Rhode Island area transmission system. Prior to that, I was employed as a transmission planning engineer at NSTAR for six years. I began my employment as a planning engineer with Boston Edison Company, which is the predecessor of NSTAR, in August of 1994. I am also a Registered Professional Engineer in the Commonwealth of Massachusetts.

Q. Are you familiar with Narragansett Electric's Southern Rhode Island Transmission Project (the "Project")?

A. Yes, I am. I conducted the study of the Southern Rhode Island area that determined the need for the transmission reinforcements of the Project. The study is documented in the report "Southwest Rhode Island Transmission Supply Study" dated October 2003 ("October, 2003 Transmission Study"), included as Appendix A to the Environmental Report (ER).

Q. What is the scope of your testimony in this proceeding?

A. In my testimony, I will summarize the planning process by which National Grid identifies a need for transmission system improvements, describe the transmission planning study which I conducted and address several alternatives which we examined as part of the process. A more detailed description is contained in Chapter 3.0 of the ER and my study, the October, 2003 Transmission Study, which is Appendix A to the ER.

Q. Please describe the process by which National Grid determines that transmission system improvements are necessary.

A. The process by which National Grid determines that transmission system improvements are necessary is described in detail in Sections 3.1 and 3.2 of the ER. In general, transmission planning studies are undertaken to analyze system performance and determine whether facilities might be needed to maintain reliable electric power to the transmission system. The reliability standards for the New England Power Pool (available at www.iso-ne.com), of which National Grid is a member, and the National Grid Transmission Planning Guide (Attachment MS-1 to this testimony) are used to assess the reliability of the system. The standards and guide require that National Grid's transmission system be designed so that facility loadings (the amount of power being carried by the facility) are kept within capabilities and transmission equipment is kept within reasonable range of voltage for foreseeable contingencies such as the loss of a single element like a major transmission line.

To ensure that the transmission system continues to meet these reliability criteria, electrical system studies are conducted for an area for a given period of time, commonly looking out 10 to 15 years. The studies involve computer simulations of power flow. Normal conditions and various contingency conditions (described in the October, 2003 Transmission Study) are simulated. The flow and voltage levels on the transmission lines and substation buses are monitored and checked to confirm that the flows and voltage levels remained within their capabilities. The flow capabilities are determined using maximum allowable component temperatures as criteria. The temperatures are fixed by manufacturers' design, American National Standards Institute (ANSI) standards, known material properties, or, in the case of a transmission line, the design basis of the line. The range of allowable voltage level is fixed by manufacturers' design and ANSI standard. In cases where the simulations indicate that loading or voltage on a facility exceeds its capabilities, changes to the facility or the system are evaluated to keep the facility within capabilities.

Q. Are all of the components of the Project identified in the October, 2003 Transmission Study?

A. No. The Tower Hill Substation and associated tap lines were a result of an area distribution study which Alan LaBarre will describe. The other components (L-190 115 kV transmission line extension and reconductoring components) were identified in the October, 2003 Transmission Study.

Q. Please describe the October, 2003 Transmission Study and summarize its conclusions.

A. To ensure that the Southern Rhode Island (SRI) area continued to meet the reliability criteria, electrical system studies were conducted for the period through the year 2010. The results were documented in the October, 2003 Transmission Study. The study showed that the transmission supply to the SRI area did not adequately meet the reliability criteria under summer peak load conditions for various contingency conditions. Two specific concerns were: a) unacceptably low voltages were observed at the West Kingston Substation located in South Kingstown, the Kenyon Substation located in Charlestown, and the Wood River Substation located in Charlestown, for the loss of the 115 kV line G-185S from Kent County Substation in Warwick to West Kingston Substation; and b) excessive loading on the 115 kV line G-185S for the loss of the 115 kV line 1280, from Mystic Substation in Stonington, Connecticut to Montville Substation in Montville, Connecticut. A geographic diagram showing these concerns is attached as Exhibit MS-2.

Q. Please explain what the results of low voltage and excessive loading are for the Southern Rhode Island area.

A. The unacceptably low voltages that result from the loss of the 115 kV line G-185S could potentially lead to a slow voltage recovery or a voltage collapse due to the resulting weak system. Voltage drops due to disturbances result in motor loads such air conditioning, heat pumps, and refrigeration to slow down. The motor loads will draw very high currents when starting or when slowed because of a disturbance. The higher currents result in lower voltages which could lead to the motors stalling. With large loads and inadequate system support, such as transmission reinforcement, a voltage collapse could follow which results in tripping of lines and load which leads to a blackout.

Excessive loading on the 115 kV line G-185S could result in damaging the transmission line by heating up the wire beyond its capability and resulting in annealing the wire. An annealed wire could sag below its sag limit creating safety concerns. The wire could sag to the point where it could make contact with an object such as a tree creating a disturbance which would lead to tripping the line, or sag to the point where it could lead to a public safety hazard. Tripping the 115 kV line G-185S while the 115 kV line 1280 is out of service will result in the loss of all load (blackout condition) in the SRI area and the southeast Connecticut area served by this transmission path.

Q. Please describe the alternatives considered in the October, 2003 Transmission Study and its conclusions.

A. <u>Alternatives</u>

Four transmission alternative solutions, including the proposed solution, were studied to address the problems. These alternatives were as follows:

- Proposed solution

- 115 kV capacitors and reconductoring alternative
- FACTS device and reconductoring alternative
- 345 kV alternative.

The alternative solutions were evaluated out through the year 2020 assuming loads provided by Distribution Planning and based on the 2001 PSA forecast, which is the Company's forecast of demand for the distinct power supply areas.

Proposed Solution

The proposed solution consists of:

- Extending the existing 115 kV line L-190 from the Old Baptist Road Tap Point, located in East Greenwich, 12.3 miles to the West Kingston Substation.
- Tying in the extension at the West Kingston Substation with a second 115 kV breaker.
- Re-terminating the existing West Kingston T2 115–34.5 kV transformer from the 115 kV line 1870N to the new 115 kV line L-190 extension.
- Reconductoring the existing section of the 115 kV line L-190 from Kent County Substation to the Old Baptist Road Tap Point.
- This solution also included the recommendation to reconductor the 115 kV line G-185S from Kent County Substation to the Old Baptist Road Tap Point at a future date.

To address the immediate voltage concern, the solution included the installation of seven distribution station capacitor banks at the West Kingston, Kenyon, and Wood River Substations in addition to a specialized Programmable Logic Control (PLC) at the West Kingston Substation. These capacitor banks and the PLC will maintain voltages and prevent slow voltage recovery or potential voltage collapse until the 115 kV line L-190 extension is complete. This solution had a 2003 study grade cost estimate of $13.3 million. This estimate does not include the reconductoring of the 115 kV lines 1870N from West Kingston Substation to Kenyon Substation and 1870 from Kenyon Substation to Wood River Substation or the cost of the proposed Tower Hill Substation and tap lines.

A variation of the proposed solution included the installation of a Dynamic VAR (D-VAR) device as an alternative to the seven distribution station capacitor banks and the PLC. This variation was dismissed due to the higher cost of the D-VAR which was twice the cost of the distribution station capacitor banks with the PLC. This solution had a 2003 study grade cost estimate of $15.4 million.

<u>115kV Capacitors and Reconductoring Alternative</u>

The 115 kV capacitor and reconductoring alternative included the following:

- Six 10 MVAr 115 kV station capacitor banks at the Kenyon Substation to address the voltage concerns.
- Reconductoring the 115 kV line G-185S from the Old Baptist Road Tap Point to the West Kingston Substation.

This alternative also included the recommendation for additional significant reinforcement such as the 115 kV line L-190 extension prior to the end of the study period in addition to the reconductoring of the existing 115 kV line L-190 from the Kent County Substation to the Old Baptist Road Tap Point and the 115 kV line G-185S from the Kent County Substation to the Old Baptist Road Tap Point. The 2003 study grade cost estimate for this alternative was $16.3 million.

FACTS Device and Reconductoring Alternative

The FACTs device and reconductoring alternative included the following:

- A 60 MVAr Flexible AC Transmission System (FACTS) device at the Kenyon Substation to address the voltage concerns.
- Reconductoring the 115 kV line G-185S from the Old Baptist Road Tap Point to the West Kingston Substation.

This alternative also included the recommendation for additional significant reinforcement such as the extension of the 115 kV line L-190 prior to the end of the study period in addition to the reconductoring of the existing 115 kV line L-190 from the Kent County Substation to the Old Baptist Road Tap Point and the 115 kV line G-185S from the Kent County Substation to the Old Baptist Road Tap Point.

Two FACTS devices that provide reactive compensation were included as variations in this alternative. These two devices were the Static Synchronous Compensator (STATCOM) and the Static Var Compensator (SVC). A FACTS device was considered due to the fast, smooth response that it provides. The fast and smooth reactive response will address the switching voltage variation concerns that are an issue with fixed capacitors and will help better address the slow voltage recovery and potential voltage collapse concerns. The SVC variation alternative had a 2003 study grade cost estimate of $20.5 million. The STATCOM variation alternative had a 2003 study grade cost estimate of $21.4 million.

345kV Alternative

The 345 kV alternative included the following:

- a new 345 kV line from Kent County Substation 51 miles to Montville Substation, located in Montville, CT.
- a new 345-115 kV substation in the Charlestown, Rhode Island vicinity to connect into the existing 115 kV transmission lines.

To address the immediate voltage concern, this alternative included the installation of seven distribution station capacitor banks at the West Kingston, Kenyon, and Wood River Substations in addition to a specialized Programmable Logic Control (PLC) at the West Kingston Substation. This alternative had a 2003 study grade cost estimate of $108.1 million. This estimate assumed the construction of a new substation on a Company-owned site.

<u>Load Forecast Update</u>

The proposed solution was reviewed using the latest forecast at the time of the October, 2003 Transmission Study. The 2003 PSA forecast was used for this review. The review was performed due to the considerable load growth in the area. The higher loads resulted in a determination that the L-190 extension and the reconductoring of the existing section of the 115 kV line L-190 from Kent County Substation to the Old Baptist Tap Point are needed immediately and the reconductoring of the section of the 115 kV line G-185S from Kent County Substation to the Old Baptist Tap Point is advanced by seven years from 2019 to 2012. Due to the time required to complete the Project, a short term solution was implemented to address the immediate thermal loading concerns. Structure replacements and vegetation clearing on the G-185S ROW allows for the existing G-185S line to operate at higher temperatures without violating sag limitations.

This allows for a higher loading capability in the short term until the Project is complete.

Evaluation of Alternatives

The alternatives were compared based on cost, technical performance, and operability. The proposed solution had the lowest 2003 study grade estimated cost. In addition, the proposed solution was selected because of its superior thermal and voltage performance over the second and third alternatives. The proposed solution also performed better through the study period and allows for future system expandability. Ultimately, a strong source to and from Connecticut will be needed to secure supply to SRI area. The proposed solution provides for a more robust system. From an operational perspective, the second alternative, which includes 115 kV capacitor banks, is inferior to the proposed solution. As the load continues to grow, the coordination of switching the capacitor banks would become more difficult. One problem with this alternative would be the long term outage concerns if the capacitors were to fail until the equipment could be replaced or repaired. The second and third alternatives also include the reconductoring of the G-185S line from the Old Baptist Road tap to the West Kingston Substation. During construction for the second and third alternatives, there would be periods when the G-185S line would be out of service and unavailable. Without a second line from Kent County to West Kingston Substations, this will require most of the SRI load to be served from Connecticut alone during this outage period. This would put the SRI load at considerable risk and would require the work to be done at the lightest load periods which limits the time window to do the work. Although the fourth alternative which included a new 345 kV line performed well technically through the study period, it was not selected due to its significantly higher cost. In addition, it provided more capability than is needed for the local SRI area needs. Thus the proposed solution was chosen over the alternatives based on economics, performance, operability, reliability, constructability, and future system expandability.

As part of economic evaluation, the 30 year Total Cumulative Present Worth Revenue Requirement (CPWRR) was also calculated and summarized in the report. The CPWRR was provided as one means of economic comparison of the alternatives. It has since been discovered that the tool, which is a revenue requirements economic spreadsheet that is used to calculate the CPWRR, was missing a parameter. The interest rate had been inadvertently removed from the economic spreadsheet. Thus the CPWRR values provided in the report are not accurate. With an interest rate included, the CPWRR for the second alternative which includes the 115 kV capacitor bank has the lowest CPWRR. However, this alternative is still not the recommended alternative based on its performance, operability, and reliability. In addition, based on the higher actual load growth and updated load forecasts, the performance of the second alternative has decreased even further which makes this alternative even less attractive.

<u>Reconductoring 1870N and 1870 115kV Transmission Lines</u>

The October, 2003 Transmission Study also included the recommendation to reconductor the 115 kV line 1870N from West Kingston Substation to Kenyon Substation and the 115 kV line 1870 from Kenyon Substation to Wood River Substation in addition to the extension of the 115 kV Line L-190. Reconductoring these lines in addition to the extension and reconductoring of the 115 kV line L-190 will allow for the removal of the

1870 Special Protection System (SPS) that currently exists on the 115 kV line 1870S from the Wood River Substation to the Shunock Substation in North Stonington, Connecticut.

An SPS is a protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. The 1870 SPS was originally installed as an emergency short term measure to allow higher Connecticut import capability to address reliability concerns related to generation outages in Connecticut. Without the SPS, the G-185S / 1870 / 1280 115 kV transmission path limits Connecticut import capability following tripping of the 345 kV transmission path between Sherman Road Substation and Card Street Substation. The SPS opens this transmission path to prevent overloading it upon loss of the critical 345 kV tie and thus allowing the import to Connecticut to take place over other transmission paths.

The operation of the SPS results in the separation of the 115 kV transmission path between Wood River Substation and Shunock Substation and exposes these areas to loss of load for the next contingency. Eliminating the 1870 SPS will remove the reliability exposure that SRI is exposed to if the SPS operates. The 2003 study grade cost estimate of these upgrades is $2.9 million.

Q. Will the Project provide support or assistance for Connecticut utilities?

A. The transmission system is an interconnected system and its basic function is to carry power from the generators to the load. The transmission system must be able to transport electricity in either direction across state boundaries just as we need the capability to move people and commodities along an interstate highway across state lines.

The SRI area and part of the southeast Connecticut area are primarily served by a 115 kV transmission path that is tied to the transmission network at Montville Substation in Connecticut at one end of the path and at Kent County Substation at the other end of the path. A geographical diagram of the area that includes the transmission lines and substations can be found in the ER as Figure 3-1. As discussed on page 4, Transmission planning studies identified reliability concerns on this path located in the SRI area. The Project will address these concerns and ensure reliable service to the SRI area and the southeast Connecticut area by maintaining acceptable voltages and removing the potential for loading one end of the transmission path above its capability while the other end is out of service.

In addition, the Project will also allow for the removal of the 1870 SPS. A discussion of the SPS is included on page 12. The Project will reinforce the transmission path so that the SPS is no longer necessary and remove the reliability exposure to the load served by this transmission path that the SPS introduced.

Q. What systemic alternatives were considered for the Project?

A. There are a number of alternatives which are described in Sections 3.4, 5.5, and 5.6 of the ER. The alternatives, which are described in Section 3.4, are included in the October, 2003 Transmission Study. These alternatives include two “No Build” alternatives and a 345 kV voltage alternative. These alternatives were summarized in an answer to a previous question on page 5, which described the October, 2003 Transmission Study.

Q. Please describe the alternatives which are discussed in Section 5.5 of the ER.

A. These alternative sources of supply were a connection from the east (Aquidneck Island) and upgrades in Connecticut.

<u>Connection from Aquidneck Island</u>

Three variations of the connection from Aquidneck Island were studied. A geographic diagram of Variation A can be found in the ER as Figure 5-3. As described in the ER, the common components of Variations A and B included:

- an overhead 115 kV transmission line from West Kingston Substation 12.0 miles to Rome Point at the shore in North Kingstown
- an underground cable from the termination of the overhead line 0.2 miles to the shore
- a submarine 115 kV cable under the West Passage of Narragansett Bay (2.0 miles)
- an underground 115 kV cable across Jamestown (3.3 miles)
- a submarine 115 kV cable under the East Passage of Narragansett Bay 2.0 miles to a landfall in Newport
- an underground 115 kV cable from the landfall 0.9 miles to Gate 2 Substation in Newport.

Variation A also included distribution station capacitor banks at the Kenyon, Wood River, and West Kingston Substations, and at Gate 2 Substation, a new 115-69 kV substation to connect the new 115 kV line to the existing 69 kV system. Studies indicated that Variation A had poor technical performance with unacceptable system voltages. For this reason, this variation was dropped from further consideration.

Variation B also included distribution station capacitor banks at the Kenyon, Wood River, and West Kingston Substations, converting the existing 69 kV lines 61, 62, and 63 from Gate 2 Substation to Dexter Substation in Portsmouth to 115 kV, reconstructing the Gate 2 Substation, the Navy Substation in Middletown, and the Jepson Substation in Portsmouth for 115 kV operation, and reconstructing the Dexter Substation as a 115 kV switch yard. Upgrades also included reconductoring the 115 kV line L14 from Tiverton Tap in Tiverton to Dexter Substation, the 115 kV line M13 from Tiverton Tap to the Bent Rd, Bates Substation Tap in Tiverton, the 115 kV line G-185S from Kent County Substation to West Kingston Substation, the 115 kV line 1870N from West Kingston Substation to the Kenyon Substation, and the 115 kV line 1870 from Kenyon Substation to Wood River Substation.

The total capital cost of Variation B is $83 million. The time required to build Variation B would be significantly longer than the proposed solution due to technical complexities. Based on the cost, timing and other factors, Variation B was rejected in favor of the Project.

Variation C included:

- an overhead 115 kV transmission line from West Kingston Substation 12.0 miles to the shore in North Kingstown
- an underground cable from the termination of the overhead line 0.2 miles to the shore
- a submarine 115 kV cable under the West Passage of Narragansett Bay (2.0 miles)
- an underground 115 kV cable across Jamestown (2.3 miles)
- a submarine 115 kV cable under the East Passage of Narragansett Bay 3.2 miles to a landfall in Middletown

- an underground 115 kV cable from the Middletown landfall 2.9 miles to Jepson Substation.

This alternative also included distribution capacitor banks at West Kingston, Kenyon, and Wood River Substations, a new 115-69 kV substation at Jepson to connect the 115 kV to the 69 kV system, reconstructing Dexter Substation to a 115 kV switch yard, converting the 69 kV lines 61 and 62 from Jepson Substation to Dexter Substation to 115 kV, reconductoring the 115 kV line L14 from Tiverton Tap to Dexter Substation, the 115 kV line M13 from Tiverton Tap to Bent Rd, Bates Substation Tap, the 115 kV line G-185S from Kent County Substation to West Kingston Substation, the 115 kV line 1870N from West Kingston Substation to Kenyon Substation, and the 115 kV line 1870 from Kenyon Substation to Wood River Substation.

The total capital cost of Variation C is $79 million. The time required to build Variation C would be significantly longer than the proposed solution due to technical complexities. Based on the cost, timing and other factors, Variation C was rejected in favor of the Project.

<u>Connecticut Upgrades</u>

Another alternative source of supply is possible from Connecticut. It was considered that a second 115 kV transmission line built in parallel with the existing 115 kV line 1280 from Montville Substation to Mystic Substation could address the reliability concerns in southern Rhode Island. However, this alternative would ultimately benefit the reliability of the southeast Connecticut area more than the SRI area. In the long term, reliability concerns would return to SRI and reinforcement would still be needed to address the growing load demand in SRI. In addition, the reconductoring of the 115 kV line G-185S from Kent County to West Kingston Substation, the 115 kV line 1870N from West Kingston Substation to Kenyon Substation, and the 115 kV line 1870 from Kenyon Substation to Wood River Substation would still be required to remove the 1870 Special Protection System.

Connecticut upgrades would only defer, not eliminate, the need for the proposed Project. Based on this, technical performance, and other considerations, this alternative was rejected in favor of the SRI Project.

Q. Please describe the alternatives which are discussed in Section 5.6 of the ER.

A. These alternative technologies are distributed generation ("DG"), demand side management ("DSM") and alternative voltages. Alternative technologies such as DG and DSM are used to reduce the existing and projected demands on the existing transmission system. DG means small generators of kW to multi-MW size installed at a customer's point of use. Generation is based on a competitive market model and it did not respond to the market needs in SRI, thus National Grid has an obligation to provide the reinforcements necessary to maintain reliable service to SRI area.

DSM is geared toward reducing overall energy usage at customer facilities. In an area of high load growth such as southern Rhode Island, DSM has limited use. These programs can only defer, not eliminate, the need for reinforcements in the transmission system in SRI. A targeted demand response (TDR) project is being conducted in the SRI area. TDR involves enrolling customers to shed load upon request by National Grid during emergency loading events in exchange for an economic incentive. This new TDR program began in the summer of 2005. The program was filed with PUC under Docket No. 3680 with two follow-up reports on the Enrollment and Curtailment Events through September 30, 2005. There were very limited results for last summer. It is expected that the TDR program will be best suited as a stop-gap measure rather than a long term alternative solution to the needs of SRI. Thus National Grid is pursuing TDR / DSM programs in the SRI area in preparation for having it available for short term operating relief in the event the SRI Project is not completed on schedule.

The 345 kV alternative was included in the October, 2003 Transmission study and is summarized in the answer to a previous question on page 5 which describes the October, 2003 Transmission Study.

A 34.5 kV alternative was also considered. This alternative considered supplying the distribution load via the distribution system from outside of the area of concern. This alternative would supply the load from the Kent County Substation due to its proximity to the load and its adequate capacity. This alternative included a new 115-34.5 kV substation at the Kent County site with three 34.5 kV circuits to serve the load. Due to the number of miles of 34.5 kV circuits it is uncertain whether there would be voltage reliability concerns under contingency conditions for this alternative. There are also potential environmental impacts associated with the construction of this alternative. The total estimated cost of the 34.5 kV alternative is $78.0 million. This alternative was not chosen due to its significantly higher cost, the potential technical challenges, and the environmental impact.

Q. What is the conclusion of your analysis?

A. The best alternative is the extension of L-190 from Old Baptist Road Tap point to the West Kingston Substation and the associated reconductoring projects. The proposed solution was chosen over the other alternatives based on economics, environmental factors, schedule, reliability, system operation, and technical performance. The Project is needed and is the most cost effective and efficient means to promote reliability to the customers in the SRI area.

Q. Does this complete your testimony?

A. Yes, it does.

ATTACHMENTS

MS-1	National Grid Transmission Planning Guide (6/29/04)
MS-2	Geographic map of area transmission system showing reliability concerns

National Grid

New England Power Company
Niagara Mohawk Power Corporation

TRANSMISSION PLANNING GUIDE

TRANSMISSION PLANNING GUIDE

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1.0 OBJECTIVE OF THE TRANSMISSION PLANNING GUIDE

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid USA (NGUSA) transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The guide is a design tool and is not intended to address unusual or unanticipated operating conditions.

2.0 PLANNING AND DESIGN CRITERIA

All NGUSA facilities that are part of the bulk power system and part of the interconnected NGUSA system shall be designed in accordance with the latest versions of the New England Power Pool (NEPOOL) standards, New York State Reliability Council (NYSRC) Reliability Rules, and the Northeast Power Coordinating Council (NPCC) criteria and the NGUSA criteria. The fundamental guiding documents are the "Reliability Standards for the New England Power Pool," the "New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System," the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Bulk Power System Protection Criteria" (NPCC Document A5), and this document.

All NGUSA facilities that are not part of the bulk power system, but are part of the interconnected NGUSA system shall be designed in accordance with the latest version of this document.

All NGUSA or NGUSA transmission customers' facilities which are served by transmission providers other than NGUSA shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NEPOOL, NYSRC, and NPCC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards which are not addressed by any of the documents referenced in this guide.

3.0 OPERATIONAL CONSIDERATIONS IN PLANNING AND DESIGN

The system should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- optimization of post contingency switching operations
- reduction of operational risks
- judicious use of Special Protection Systems (SPSs)

1.0 BASIC TYPES OF STUDIES

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Loadflow, Stability, Short Circuit, and Protection.

2.0 STUDY HORIZON

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to ten-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six to ten years). The long term time frame may be extended for development of long term transmission infrastructure planning, to aid in development of long term expansion plans, and to assess the adequacy of proposed facilities beyond the ten year horizon. Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.0 FUTURE FACILITIES

Planned facilities should not automatically be assumed to be in-service during study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

4.0 EQUIPMENT THERMAL RATINGS

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing rating procedures are based on guidance provided by the NEPOOL System Design Task Force (SDTF), the NYPP Task Force on Tie Line Ratings, and industry standards. A common rating procedure has been developed for rating NGUSA facilities in New England and New York which will be applied to all new and modified facilities. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes	requires immediate action to reduce loading below the STE rating
Underground Cables[1]	Continuous	Loading must be reduced below the 100 hr or 300 hr rating within 4 hours[2]	Loading must be reduced below the 100 hr or 300 hr rating within 15 minutes	requires immediate action to reduce loading below the STE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	requires immediate action to reduce loading below the STE rating

[1] Ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hr or 300 hr period, loading of the cable must be reduced below the Normal rating. Either the 100 hr or the 300 hr rating may be utilized after the transient period, but not both. If the 100 hr rating is utilized, the loading must be reduced below the Normal rating within 100 hr, and the 300 hr rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours.

[3] The transformer STE rating is based on a 30 minute duration to provide additional conservatism, but is applied in operations as a 15 minute rating.

4.1 OTHER EQUIPMENT

Industry standards and input from task forces in New England and New York should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

4.2 HIGH VOLTAGE DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

5.0 MODELING FOR LOADFLOW STUDIES

The representation for loadflow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

5.1 FORECASTED LOAD

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance.

The Point of Delivery for loadflow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between NGUSA and the Transmission Customer.

To address forecast uncertainty, the peak load forecast should include forecasts based on normal and extreme weather. Due to the lead time required to construct new facilities, planning should be based conservatively on the extreme weather forecast.

5.2 LOAD LEVELS

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the extreme weather peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

5.3 LOAD BALANCE AND HARMONICS

Balanced three-phase 60 Hz ac loads are assumed at each Point of Delivery unless a customer specifies otherwise, or if there is information available to confirm the load is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

5.4 LOAD POWER FACTOR

Load Power Factor for each delivery point is established by the active and reactive load forecast supplied by the customer in accordance with section 5.1 The Load Power Factor in each area in New England should be consistent with the limits set forth in Operating Procedure 17 (OP17).

5.5 REACTIVE COMPENSATION

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. NGUSA should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator active power output for each generator connected to the transmission system.

5.6 GENERATION DISPATCH

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Dispatching to the interface limits may stress the transmission system in excess of transfer levels that are considered normal.

5.7 FACILITY STATUS

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section B, paragraph 3.0.

6.0 MODELING FOR STABILITY STUDIES

6.1 DYNAMIC MODELS

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NEPOOL, NYSRC, and NPCC.

6.2 LOAD LEVEL AND LOAD MODELS

Stability studies within New England typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed for several unit dispatches at a system load level of 45% of peak system load. At least one unit dispatch at 100% of system peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Stability studies within New York typically exhibit the most severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of rotor angle stability and are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system.

Loads outside NEPOOL are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

6.3 GENERATION DISPATCH

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

7.0 MODELING FOR SHORT CIRCUIT STUDIES

Short Circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed.

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

8.0 MODELING FOR PROTECTION STUDIES

Conceptual protection system design should be performed to ensure adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from loadflow, stability, and short circuit studies to ensure feasibility of the conceptual design.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements to a level below the required circuit rating.

9.0 DEVELOPMENT AND EVALUATION OF ALTERNATIVES

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions based on safety, performance, reliability, environmental impacts, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation that is summarized concisely in a report.

9.1 SAFETY

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance
- adequate facilities to allow for staged construction of new facilities

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

9.2 PERFORMANCE

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

9.3 RELIABILITY

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with NEPOOL, NYSRC, and NPCC practice. Defined outage conditions that the system must be designed to withstand are listed in Section C. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

Application of this guide ensures that all customers receive an acceptable level of reliability, although the level of reliability provided through this approach will vary. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

9.4 ENVIRONMENTAL

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way are proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid USA policies.

9.5 ECONOMICS

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

A cash flow model is used to assess the impact of each alternative on the National Grid USA business plan. A cumulative present worth of revenue requirements model is used to assess the impact of each alternative on the customer. Evaluation based on one or both models may be required depending on the project.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

9.6 TECHNICAL PREFERENCE

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

9.7 SIZING OF EQUIPMENT

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

10.0 RECOMMENDATION

A recommended action should result from every study. The recommendation includes resolution of any potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as safety, the forecasted performance and reliability, environmental impacts, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, and complexity and lead time to license and permit.

11.0 REPORTING STUDY RESULTS

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

1.0 OBJECTIVE OF THE DESIGN CRITERIA

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

2.0 DESIGN CONTINGENCIES

The Design Contingencies used to assess the performance of the transmission system are defined in Table 1. In association with the design contingencies, this table also includes information on allowable facility loading. Control actions may be available to mitigate some contingencies listed in Section C, Table 1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NEPOOL system and the New York State Power System. Where this is the case, the system performance requirements for the local area under NGUSA design contingencies may be less stringent than what is required by NPCC criteria, NEPOOL reliability standards, or NYSRC Reliability Rules.

2.1 FAULT TYPE

As specified in Section C, Table 1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

2.2 FAULT CLEARING

Design criteria contingencies involving ac system faults on bulk power system facilities are simulated to ensure that stability is maintained when either of the two independent protection groups that performs the specified protective function operates to initiate fault clearing. In practice, design criteria contingencies are simulated based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

Design criteria contingencies involving ac system faults on facilities that are not part of the bulk power system are simulated based on correct operation of the protection system on the faulted element. Facilities that are not part of the bulk power system must be reviewed periodically to determine whether changes to the power system have caused facilities to become part of the bulk power system. National Grid utilizes for this purpose a methodology based on applying a three-phase fault, uncleared locally, and modeling delayed clearing of remote terminals of any elements that must open to interrupt the fault.

2.3 ALLOWABLE FACILITY LOADING

The normal rating of a facility defines the maximum allowable pre- or post-contingency loading to which the equipment can operate during a normal load cycle. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section B, System Studies, paragraph 4.0 "Equipment Thermal Ratings").

For normal pre-contingent and emergency transfers, no facility shall be loaded above its normal rating. For emergency transfers however, a facility may be loaded up to the LTE rating pre-contingency, if the loading duration is less than the seasonal time allowance for loading up to the LTE rating, and if the STE rating is reduced to reflect the higher pre-contingent loading.

As a planning practice, the system should be designed to avoid loading equipment above the LTE rating following a design contingency (see Section C, Table 1 contingencies a through i). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, h, and i, for momentary conditions provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid USA Transmission Control & Reporting.

The Drastic Action Limit (DAL) is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. The DAL is not used in planning studies. In some cases when the DAL may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

2.4 RELIABILITY OF SERVICE TO LOAD

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a supply can be interrupted by the loss of a radial transmission element.

Supply to load is considered to be acceptable if loss of a single non-radial transmission element will not result in a loss of load for longer than the time required for automatic switching. Decisions as to the acceptable amount of load at risk are made by the customer, and the customer is responsible for requesting alternate supply capability.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure, or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

2.5 LOAD SHEDDING

NPCC requires that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region. In some cases higher quantities of load shedding may be required by the Area or the local System Operator.

Manual or automatic shedding of any load connected to the NGUSA transmission system in response to a design contingency listed in Section C, Table 1 may be employed to maintain system security when adequate facilities are not available to supply load. However, shedding of load is not acceptable as a long term solution to design criteria violations, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

2.6 EXPECTED RESTORATION TIME

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers. When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to restoration of the failed equipment.

2.7 GENERATION REJECTION OR RAMP DOWN

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid USA Transmission Control & Reporting, and may require approval of the System Operator.

2.8 EXCEPTIONS

These Design Criteria do not apply if a customer receives service from NGUSA and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, NGUSA has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

NGUSA is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, NGUSA does not have to provide redundant transmission supplies.

3.0 VOLTAGE RESPONSE

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Section C, Table 2), and in terms of percent voltage change from pre-contingency to post-contingency (Section C, Table 3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.0 STABILITY

4.1 SYSTEM STABILITY

Stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Section C, Table 1, with due regard to reclosing. Stability shall also be maintained if the outaged element as described in Section C, Table 1, is re-energized by autoreclosing before any manual system adjustment.

In evaluating the system response it is insufficient to merely determine whether a stable or unstable response is exhibited. There are a number of system responses which may be considered unacceptable even though the bulk power system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in wide spread system collapse.
- Transiently stable response with undamped power system oscillations.
- Entry of the line 396 apparent impedance at Keswick into the Keswick GCX SPS relay characteristic.

4.2 GENERATOR UNIT STABILITY

With all transmission facilities in service, generator unit stability shall be maintained on those facilities that remain connected to the system following fault clearing, for

a. A permanent single-line-to-ground fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

b. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

Isolated generator instability may be acceptable. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

Table 1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 1 mile)	LTE[1]
c	A permanent single-line-to-ground fault on any transmission circuit, transformer, or bus section, with a breaker failure	LTE[1]
d	Loss of any element without a fault (including inadvertent opening of a switching device_	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Failure of a circuit beaker to operate when initiated by an SPS following: loss of any element without a fault, or a permanent single-line-to-ground fault on a transmission circuit, transformer, or bus section	LTE[1]
h	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
i	Permanent single-line-to-ground faults on two cables in a common duct or trench	LTE[1]

Notes:
[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

Table 2: Voltage Range

CONDITION	345 & 230 kV		115 kV[1] & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

[1] Buses that are part of the bulk power system, and other buses deemed critical by Transmission Control & Reporting shall meet requirements for 345 kV and 230 kV buses.

Table 3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV[1] & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

[1] Buses that are part of the bulk power system, and other buses deemed critical by System Control shall meet requirements for 345 kV and 230 kV buses.

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 2 and 3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to NGUSA facilities.

Bulk Power System
The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency
An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element
Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed
Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal
Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.

High Voltage dc (HVdc) System, Bipolar
An HVdc system with two poles of opposite polarity and negligible ground current.

Interface
A group of transmission lines connecting two areas of the transmission system.

Load Cycle
The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level
A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)
Loss of service to one or more customers for longer than the time required for automatic switching.

Point(s) of Delivery
The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems

A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding and conventionally switched locally controlled shunt devices are not considered to be SPSs.

Supply Transformer

Transformers that only supply distribution load to a single customer.

Transfer

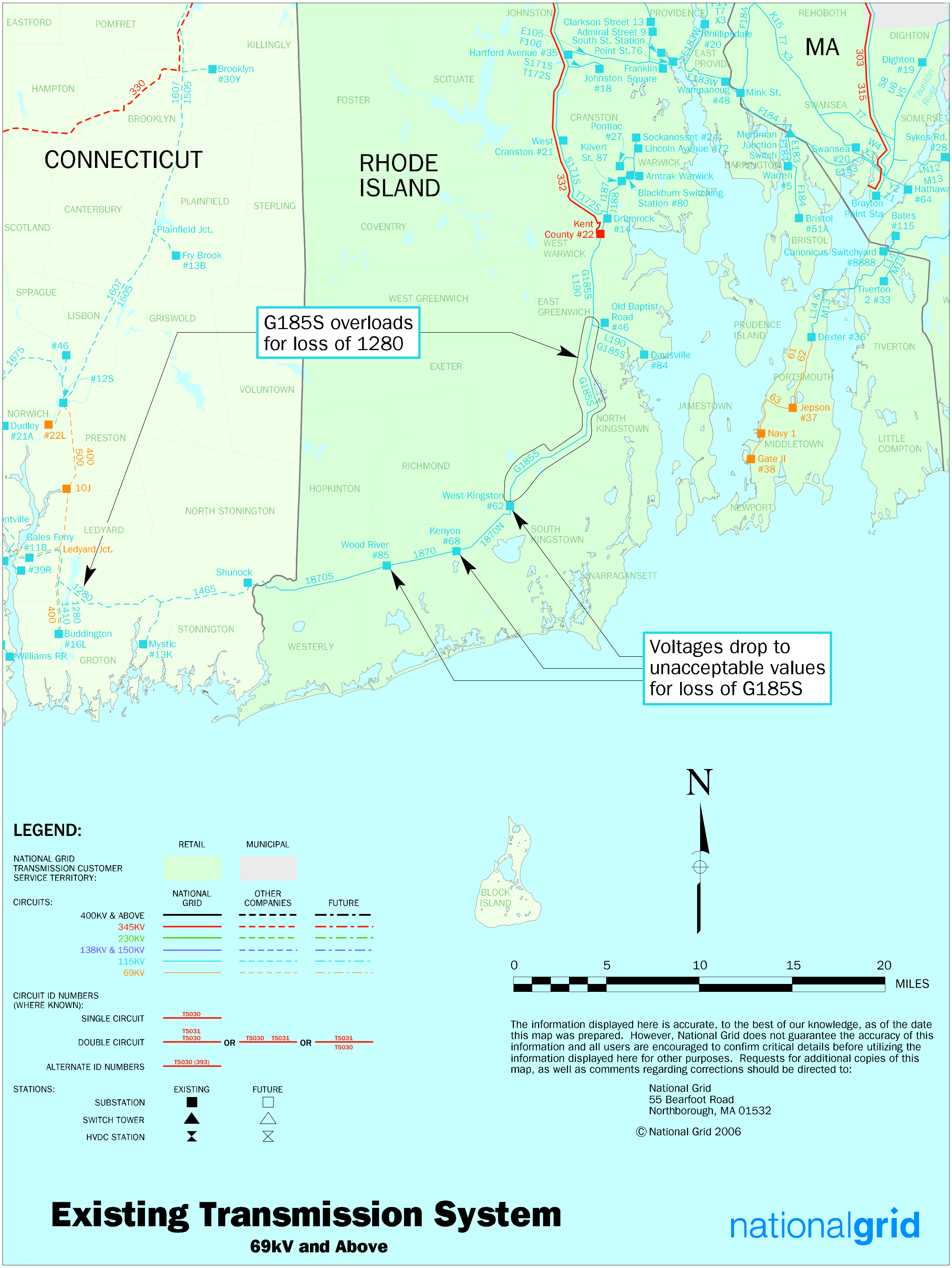
The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer

Any entity that has an agreement to receive wholesale service from the NGUSA transmission system.

Transmission Transformer

Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.


CONNECTICUT
RHODE ISLAND
MA
G185S overloads for loss of 1280
Voltages drop to unacceptable values for loss of G185S
EASTFORD
POMFRET
KILLINGLY
HAMPTON
BROOKLYN
Brooklyn #30Y
330
1607
1505
CANTERBURY
PLAINFIELD
STERLING
SCOTLAND
Plainfield Jct.
Fry Brook #13B
SPRAGUE
LISBON
GRISWOLD
1675
#46
#12S
NORWICH
Dudley #21A
#22L
PRESTON
400
500
10J
LEDYARD
Gales Ferry #11B
Ledyard Jct.
#39R
1280
1410
Buddington #16L
Williams RR
GROTON
Mystic #13K
STONINGTON
1465
Shunock
NORTH STONINGTON
VOLUNTOWN
JOHNSTON
PROVIDENCE
REHOBOTH
DIGHTON
Clarkson Street 13
Admiral Street 9
South St. Station
Hartford Avenue #35
Point St.76
Phillipsdale #20
EAST PROVIDENCE
Franklin Square
Johnston #18
Wampanoag #48
Mink St.
SWANSEA
SOMERSET
Dighton #19
Sykes Rd. #28
SCITUATE
FOSTER
CRANSTON
Pontiac #27
West Cranston #21
Kilvert St. 87
Sockanosset #24
Lincoln Avenue #72
WARWICK
Amtrak Warwick
Blackburn Switching Station #80
Merriman Junction Switch
BARRINGTON
Warren #5
Swansea #20
Brayton Point Sta
Hathaway #64
Bates #115
Bristol #51A
BRISTOL
Canonicus Switchyard #8888
Tiverton 2 #33
Dexter #36
TIVERTON
COVENTRY
Kent County #22
WEST WARWICK
Drumrock #14
EAST GREENWICH
WEST GREENWICH
Old Baptist Road #46
Davisville #84
PRUDENCE ISLAND
PORTSMOUTH
Jepson #37
Navy 1
MIDDLETOWN
Gate II #38
NEWPORT
JAMESTOWN
LITTLE COMPTON
EXETER
NORTH KINGSTOWN
RICHMOND
HOPKINTON
West Kingston #62
Kenyon #68
Wood River #85
1870
1870S
1870N
SOUTH KINGSTOWN
NARRAGANSETT
WESTERLY
G185S
L190
BLOCK ISLAND
N
0 5 10 15 20 MILES
LEGEND:
RETAIL
MUNICIPAL
NATIONAL GRID TRANSMISSION CUSTOMER SERVICE TERRITORY:
CIRCUITS:
NATIONAL GRID
OTHER COMPANIES
FUTURE
400KV & ABOVE
345KV
230KV
138KV & 150KV
115KV
69KV
CIRCUIT ID NUMBERS (WHERE KNOWN):
SINGLE CIRCUIT
T5030
DOUBLE CIRCUIT
T5031 T5030 OR T5030 T5031 OR T5031 T5030
ALTERNATE ID NUMBERS
T5030 (393)
STATIONS:
EXISTING
FUTURE
SUBSTATION
SWITCH TOWER
HVDC STATION
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Existing Transmission System
69kV and Above
nationalgrid