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TRANSMISSION PLANNING CRITERIA
(Revision 15)

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REVISION TABLE			
Revision Level	**Author**	**Date**	**Description**
Original	-	1991	- None
1st Revision	R. Mangonon	05/01/2008	- Updated Cover page and Table of Contents. - Revised Part I & II. - Added Part III & IV.
2nd Revision	R. Mangonon	06/25/2011	- Updated Cover page and Table of Contents. - Added Revision Table. - Added Sections I, II & VIII. - Updated Reference Page.
3rd Revision	R. Mangonon	06/29/2012	- Updated Cover Page and Revision Table. - Renamed document to "Transmission Design Standards".
	R. Mangonon	6/25/2013	-Updated Cover Page
4th Revision	R. Mangonon	09/10/2014	-Updated Cover Page - Revision Change
5th Revision	R. Mangonon	08/27/2015	-Revision Change -Added Section "IX. Protective Systems"
6th Revision	R. Mangonon	12/01/2015	- Revision Change -Changed RFC to RF - Changed Reference document 12 "ORU-ENGR-005" to "ORU-ENGR-006"
7th Revision	R. Mangonon	12/20/2016	- Revision Change - Added Generator Operators as part of the notification for coordination on Protection System changes if they are affected. See section IX.
8th Revision	R. Mangonon	06/07/2017	- Revision Change - Language added on Page 9 to include traditional or non-traditional transmission projects.
9th Revision	R. Mangonon	07/23/2018	- Revision Change
10th Revision	R. Mangonon	08/22/2019	- Revision Change and modified section VIII
11th Revision		6/2020	- Included provisions from NERC Standard TPL-001 in the planning criteria (Section III). -Included End-of-Life (EOL) Criteria (Section IV). - Revised interconnection procedures for new facilities (Section VII).
12th Revision	Trans. Planning	7/2021	Title Page

13th Revision	Trans. Planning	7/2022	Title Page
14th Revision	Trans. Planning	11/28/23	Title Page
15th Revision	Trans. Planning	03/1/25	- Revised Title. - Updated Section II. - Updated Section III. - Deleted Section IV. - Updated Section VI. - Updated Section VII.

Table of Contents

I. INTRODUCTION

Orange and Rockland Utilities' Transmission Planning has the task of ensuring the reliability and adequacy of the local transmission system while meeting system load growth. Transmission Planning conducts annual comprehensive studies that result in local transmission system plans. In developing these plans, Transmission Planning uses the principles and guidelines mentioned in this document to ensure that the Orange and Rockland ("O&R") local transmission system can serve current and projected distribution loads during normal and emergency conditions. These planning design standards are meant to supplement the New York Independent System Operator ("NYISO") and Pennsylvania Jersey Maryland Interconnection ("PJM") current planning process.

II. BULK POWER SYSTEM

A. Definition

The North American Electric Reliability Corporation ("NERC") defines the bulk power system ("BPS") as the facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generation facilities needed to maintain transmission system reliability.

B. Reliability

In the New York Control Area ("NYCA"), bulk power transmission planning is covered by NYISO's planning process. In the New Jersey Control Area ("NJCA"), bulk power transmission planning is covered by PJM's planning process.

The analysis and studies performed by the NYISO/PJM include, but not limited to, thermal, voltage, stability, short circuit and breaker duty and transfer limits.

The reliability criteria, guidelines and policies for the NYCA facilities shall be defined by NERC, NPCC and NYSRC. The NJCA facilities shall be covered by NERC, RFC and PJM standards and guidelines.

C. Contingencies

All contingencies shall be defined by NERC, NPCC and NYSRC for the NYCA facilities; the NJCA facilities shall be under the NERC, RF and PJM guidelines.

III. LOCAL TRANSMISSION SYSTEM

A. Definition

The local transmission system consists of all electric facilities operated at 34.5 kV system up to 345 kV system. O&R's transmission system includes BPS and BES Facilities as well as 69 kV and 34.5 kV systems (facilities in Eastern Division) and their supply transformers. However, facilities operating at 34.5 kV in O&R's Central and Western Divisions are considered part of the distribution system.

The basic functions of the local transmission system are:

(1) To deliver generation from remote sites to load centers while operating within the electrical limitations of existing transmission facilities, and supplying service at the desired time and amounts in a reliable manner;

(2) To accommodate system emergencies including outages of generation or transmission facilities without disruption of service; and,

(3) To dispatch generation from the most economical resources available while maintaining system reliability.

B. Bulk Electric System

1. Definition

NERC generally defines the Bulk Electric System ("BES") as all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher.

2. Reliability

In the NYCA, BES transmission planning is covered by O&R's planning process. In the NJCA, BES transmission planning is covered by PJM's planning process.

The reliability criteria, guidelines and policies for the NYCA facilities shall be defined by NERC, NPCC and NYSRC. The NJCA facilities shall be covered by NERC, RFC and PJM standards and guidelines.

3. Contingencies

All contingencies shall be defined by NERC, NPCC and NYSRC for the NYCA facilities; the NJCA facilities shall be under the NERC, RF and PJM guidelines.

C. Reliability

1. No Loss of Load

The Transmission System will be designed and operated to a level where no loss of load will be allowed during reasonably foreseeable contingencies. Loss of small portions of a system, such as radial portions, will be tolerated provided these do not jeopardize the integrity of the overall transmission system.

2. **Maintenance Outages**

The Transmission System will be designed to allow for maintenance outages. In cases where a substation or customers are supplied from two sources, loss of load will be accepted for reasonably foreseeable contingencies with one supply out for maintenance.

3. **Sufficient Capability**

The Transmission System will be designed with sufficient capability as can be economically justified. Losses will be reduced where possible, optimum economic generation will be provided for and the ability to purchase or sell capacity and energy through various interconnections with other utilities will be maintained.

4. **New Facilities**

New facilities will be designed to provide physical separation so that a single occurrence will not cause simultaneous loss of two supplies to the same distribution substation or load center.

5. **Restoration of Service**

The transfer of load by rearrangement of lines and busses via supervisory control and field switching and readjustment of generator outputs following outages are acceptable means to restore service.

D. Operating Conditions

1. **Normal Operating Conditions (N-0)**

The Transmission system shall be designed to serve load when the system is in normal configuration and the following criteria will be based on the most recent revision of *NERC Standard TPL-001 Table 1 Category P0 - No contingency condition*:

Thermal Ratings Criteria

No transmission facility exceeded its Normal Thermal ratings and no thermal violations observed in all divisions under normal operating conditions.

Voltage Limit Criteria

All bus voltages should be within 0.95 to 1.05 per unit of their nominal voltage. No voltage violations observed in all divisions under normal operating conditions.

Study results with proposed mitigations are summarized annually in the Transmission System Operating Summer Peak Study ('Annual Summer Study") report.

2. **Single Contingency Operating Conditions (N-1)**

The O&R transmission system shall be designed to sustain single contingency conditions such as outage of a single transmission circuit, transformer or a bus section without loss of load based on the most recent revision of *NERC Standard TPL-001 Table 1 Category P1 - Single contingency condition*. During any of the above contingencies, **no facility will be loaded above its Normal rating**. When the Normal rating is exceeded during the above single contingencies, T&S Engineering shall propose system reinforcements and/or improvements to mitigate the violation(s). The objective of these corrective measures, whether traditional transmission project or non-wires alternative (NWA) project, is to reduce the MW flow on the affected equipment below its corresponding Normal thermal rating. The maximum acceptable voltage deviation of busses in contingency conditions, after Load Tap Changers (LTCs) of transformers have operated, should not be less than 95% nor greater than 105% of the nominal bus voltage. Study results with proposed mitigations are summarized in the Annual Summer Study report.

3. Double Contingencies Operating Conditions (N-2)

The occurrences of the following specific double contingencies are to be examined for the consequences and possible solutions. However, in no case should they result in a system outage affecting more than 10% of total system peak for duration greater than four (4) hours.

a. Transmission circuit and transformer within same substation or load area;
b. Generator and either a transformer or a transmission circuit within the same substation or load area;
c. Two transmission circuits on the same structure
d. Two transformers within same substation
e. Two adjacent bus sections.

Results of the study are summarized in the Annual Summer Study report but for information purposes only.

4. Two Overlapping Single Contingency Operating Conditions (N-1-1)

O&R is currently registered as a Transmission Planner ("TP") with NERC, a summary of findings was included in this report using the most recent revision of *NERC Standard TPL-001 Table 1 – Steady State & Stability Performance Planning Events, Category P6 - Multiple Contingency (Two Overlapping Singles*). The standard allows the interruption of both firm transmission service and non-consequential load loss (i.e. load shedding) and should bring the power flow on the affected equipment **below their normal ratings and + 5% of the nominal bus voltage**. Results are summarized in the annual TP Assessment Report.

5. **Extreme Contingency Operating Conditions**

Extreme contingencies are the occurrence of multiple contingency events especially in the BPS that will subject the whole Transmission system to severe conditions and were based on *NERC Standard TPL-001 Table 1- Steady State and Stability Performance Extreme Events".* The occurrences of the following extreme contingencies, per NPCC criteria, are to be examined for possible consequences and solutions:

A. Loss of the entire capability of a generating station;
B. Loss of all lines emanating from a generating station, switching station or substation;
C. Loss of a Right-of-Way ("ROW");
D. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, which delayed fault clearing and with due regarding to reclosing;
E. The sudden dropping of a large load or major load center;
F. The effect of severe power swings arising from disturbances outside the NPCC's interconnected system; and,
G. Failure of a special protection system, to operate when required following the normal contingencies.

Results of the study are summarized in the Annual Summer Study report but for information purposes only.

E. Voltage

The Transmission System shall have supervisory or automatic controls capable of maintaining voltages at levels, which will not exceed limits of the connected equipment during both normal and contingency conditions and will allow for meeting the criteria for customer voltage as defined in the Distribution Planning Criteria.

1. **Operating Range**

   1.1. **Normal Operating Conditions**

   The voltages on the Transmission System will be maintained within ± 5% of nominal voltage under normal conditions.

   1.2 **Single Contingency Operating Conditions**

   The maximum acceptable voltage deviation during single contingency conditions after LTC transformers have operated within ± 5%, but not less than 95% or greater than 105% of nominal voltage.

2. **Reactive Requirements**

   Capacitors banks are installed in the distribution system for voltage support and loss reduction. On the transmission system, capacitor banks will be installed to provide voltage support during normal operating conditions and post-contingency conditions.

F. Generating Unit Stability

With all transmission facilities in service, generator unit stability shall be maintained on those facilities not directly involved in clearing the fault for:

1. A permanent three-phase fault or phase-to-ground fault on any generator transmission circuit, transformer or bus section cleared in normal time;
2. A permanent phase-to-ground fault on any generator transmission circuit, transformer or bus section with delayed clearing.

IV. SYSTEM FREQUENCIES

A. Standard Frequency

The standard frequency on the O&R system is nominally 60 hertz. A sustained frequency excursion of $\pm$0.2 hertz is an indication of a major load-generation unbalance and possible formation of an island. A load shedding program has been developed in order to provide selectivity and flexibility. Most generators are incapable of sustained operation below a specified minimum frequency, typically less than 58.5 hertz.

B. Automatic Underfrequency Load Shedding

Underfrequency ("UF") relays are installed at various locations throughout the system to provide protection against widespread system disturbances. The Underfrequency Load Shedding Program ("UFLS") is updated once each calendar year, and not to exceed does not exceed 15 months between updates, for the NYISO and PJM.

1. Circuit Weight

Circuits are prioritized based on the total circuit weight. This process involves applying a weight for each customer by type (hospital, public health, safety, infrastructure, control centers, gas facilities, radio towers, etc.). Generally, lower weight circuits are shed first, however, a balance must be achieved between the UFLS and manual load shed programs to minimize overlap between programs and ensure the requirements for both programs are met.

2. UF relays:

2.1. The **NPCC** requirements are for five frequency UFLS Stages based on the previous 3 year average actual peak loads. The table below describes the NPCC's requirements obtained from PRC-006-NPCC-2 Attachment C.

UFLS Table 1: Eastern Interconnection Distribution Providers and Transmission Owners with 100 MW[2] or more of peak net Load shall implement a UFLS program with the following attributes:					
UFLS Stage	Frequency Threshold (Hz)	Minimum Relay Time Delay (s)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.10	0.30	6.5 – 7.5	6.5 – 7.5
2	59.3	0.10	0.30	6.5 – 7.5	13.5 – 14.5
3	59.1	0.10	0.30	6.5 – 7.5	20.5 – 21.5
4	58.9	0.10	0.30	6.5 – 7.5	27.5 – 28.5
5	59.5	0.10	10.0	2 - 3	29.5 – 31.5

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

2.1. **RFC** requirements are for three frequency settings based on forecasted peak. The first setting requires a minimum of 10% of the year's forecasted peak to be shed at 59.3hertz. The second setting requires a minimum of 10% of the year's forecasted peak to be shed at 58.9 hertz. The third setting requires a minimum of 10% of the year's forecasted peak to be shed at 58.5 hertz.

C. Manual Load Shedding:

The Manual Load Shed Program is updated every year based on the new circuit weights and the circuits selected for the underfrequency program. Excluding circuits that serve high priority customers, such as O&R and customer critical facilities, hospitals, safety services and malls (public place for heat and air), the circuits that do not have underfrequency relays and the circuits in which the UF relays are turned off are grouped together and prioritized by circuit weight in ascending order. When these circuits are completed, the circuits with underfrequency relays turned on are prioritized by circuit weight in ascending order. Finally, after these circuits are completed, the remaining circuits (high-prioritized circuits) are prioritized by circuit weight in ascending order as well.

V. INTERCONNECTION PROCEDURES FOR NEW AND MODIFIED FACILITIES

For more information on the interconnection process of new and modified generators (e.g., photovoltaic, energy storage, rotating generation) and transmission projects, as well as end-user facilities to The Company's electric transmission system, please refer to ORU-ENGR-06A-000 – Facility Interconnection Informational Kit. For more information on the requirements for Inverter Based Resources, please refer to ORU-ENGR-008-000 – Inverter-Based Resources Performance Requirements.

VI. REFERENCES

1. **Determining Priority for Load Shed.** Orange and Rockland Utilities, Inc. Distribution Engineering Department.
2. **NERC Standard TPL-001**
3. **ORU-ENGR-06A-000** - Facility Interconnection Informational Kit
4. **ORU-ENGR-008-000** - Inverter-Based Resources Performance Requirements