OEB STAFF INTERROGATORY 1

IESO-EWT/LSL-Staff-1

Ref: IESO's Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion; Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, dated June 29, 2018
Figure 1, Page 2

INTERROGATORY

Question:

a) Please identify and describe the main drivers for the increase in the capacity requirement (MW) between:

   i. 2019 and 2020

   ii. 2022 and 2023

RESPONSE

a) i. and ii. The main drivers for the increase in the capacity requirement (MW) between 2019 and 2020 then 2022 and 2023 are forecast increases in load and the expiry of contracts with generators

Page Intentionally Blank

OEB STAFF INTERROGATORY 2

IESO-EWT/LSL-Staff-2

Ref: IESO's Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion; Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, dated June 29, 2018
Conclusion and Table 2, Pages 5-6

INTERROGATORY

Questions:

a) Can the IESO please explain how the costs of delay to in-service dates are meant to be interpreted? For example:

   i. Would a project with an in-service date of December 2020 trigger a total delay cost of $17 million? If not, please explain in detail.

   ii. Would a project with an in-service date of December 2021 trigger a total delay cost of $17 million plus $19 million? If not, please explain in detail.

b) How does the IESO expect the costs of delay to the in-service date would be impacted, if a project was to come into service midway through the year? For example, would the IESO expect that the costs of delay are linearly distributed over the course of 12 months?

c) The IESO has stated that it does not support delaying the in-service date beyond the end of 2022, as the increased risks to system reliability and the associated cost uncertainties are unacceptable.

   iii. Does this mean that in practice, the total potential costs of delay for 2023 and 2024 in Table 2 (i.e. $39 million and $45 million, respectively) are not feasible?

d) Is there a cost to the system associated with the new transmission line between Wawa and Thunder Bay not being in-service in 2019? If yes, can the IESO provide that cost as well? If not, please explain.

e) Can the IESO please confirm whether there are currently any costs to the system as a result of the new transmission line between Wawa and Thunder Bay not being in-service (for example, line losses)? If so, what does the IESO estimate these costs to be?

RESPONSE

a) For each year in Table 2 of the IESO's Addendum to the 2017 Updated Needs Assessment, the IESO is presenting the estimated cost in that year if the East-West Tie Expansion was not in-service. These costs should be added together to get the full cost for the period of the delay.

i. and ii. Yes, this is how the table is meant to be interpreted.

b) If a project was to come into service midway through the year, it may impact the total cost of the delay in a positive or negative manner depending on how the incremental capacity is acquired (i.e. while you may require a resource for a shorter duration the fact that you need it for a shorter duration could also increase the cost of that resource as it may come at a less competitive price as a result). The IESO would expect the cost to fall within the projected cost range identified.

c)

iii. The determination that the IESO does not support delaying the East-West Tie Expansion project beyond the end of 2022 was predominantly based on the increased risks to system reliability as outlined on pages 3-4 of the IESO's Addendum to the 2017 Updated Needs Assessment. Notwithstanding these risks, the IESO expects any capacity acquired would be within the Projected Cost Range identified in Table 1 of the Addendum to the 2017 Updated Needs Assessment.

d) There is no cost in 2019 as the East-West Tie Expansion was not expected to be in service until 2020.

e) The current costs (i.e. in 2018) due to additional line losses and foregone energy associated with the East-West Expansion not being in-service are similar to those outlined in Table 2 of the IESO's Addendum to the 2017 Updated Needs Assessment. There are currently no capacity costs associated with the line not being in service.

OEB STAFF INTERROGATORY 3

IESO-EWT/LSL-Staff-3

Ref: IESO's Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion; Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, dated June 29, 2018

INTERROGATORY

Questions:

a) Can the IESO please explain how the costs of delay for this transmission project would ordinarily be paid for?

b) Is the normal cost treatment identified in part (a) above appropriate in the case of a delay to either NextBridge's East-West Tie or Hydro One's Lake Superior Link project in the IESO's opinion?

RESPONSE

a) The costs of a delay relating to capacity would ordinarily be recovered through Global Adjustment or uplifts, depending on the procurement mechanism used. Costs relating to energy would be recovered through energy market revenue, currently at the Hourly Ontario Energy Price. Costs relating to transmission losses would be recovered through uplifts.

b) Absent any other cost-recovery method deemed appropriate by the OEB, if there is a delay to the in-service date of the East-West Tie Expansion, the IESO will take the necessary actions to maintain system reliability and the cost-recovery mechanisms outlined in (a) would apply.

Page Intentionally Blank

OEB STAFF INTERROGATORY 4

IESO-EWT/LSL-Staff-4

Ref: IESO's Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion; Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, dated June 29, 2018
Table 2, Page 5

INTERROGATORY

Question:

a) Is the IESO able to track actual costs for the cost categories listed in Table 2 (i.e. Potential Capacity Costs, Energy Costs and Foregone Loss Savings), if a delay were to occur? Can these cost categories be tracked separately?

RESPONSE

a) The IESO could track potential capacity costs as the interim measure is expected to be acquired through a procurement but the IESO cannot track the cost of real-time differences in energy production costs and foregone loss savings related to a project delay.

Page Intentionally Blank

BZA INTERROGATORY 1

BZA-1

Reference: EB-2011-0140 Exhibit Letter to OPA on EWT Consultation (May 31 , 2011)
EB-2011_0140 Aboriginal Consultation Record (May 9, 2012)

The Ontario Power Authority was delegated the procedural aspects of Crown consultation with respect to the East-West tie project for the period prior to the Board designating a transmitter. This is confirmed in the May 31, 2011 letter from Jon Norman, of the Ministry of Energy to Michael Lyle of the Ontario Power Authority.

The OPA filed its consultation record and an explanation of the consultation activities with the Board on May 9, 2012.

INTERROGATORY

a) Please advise if as a result of the OPA/IESO consultation if the OPA/IESO made a determination of which First Nation communities were most adversely affected by the project. If so, please provide copies of any and all documentation/correspondence/memos etc. concerning this determination.

b) Please advise if anyone from any other agency or ministry of the Ontario Government, including the Ministry of Energy, ever communication which First Nation communities may be most adversely affected by the project. If so, please provide copies of any and all documentation/correspondence/memos etc. concerning this determination.

c) Specifically, are you aware if anyone has ever determined that BZA is less adversely affected by the project? If so, please provide copies of any and all documentation/correspondence/memos etc. concerning this determination.

d) Please advised if the IESO (formerly OPA) was delegated any further procedural aspects of the Crown to consult, or monitor consultation efforts, after May 9, 2012.

e) If the OPA/IESO undertook further consultation, or monitored any consultation efforts, with First Nation and Metis communities after the May 9, 2012 date provide an updated record of consultation activities.

f) Please provide copies of any documents/correspondence/memos etc. including correspondence between the Ministry of Energy and the IESO/OPA concerning consultation.

g) If the OPA/IESO was relieved of the obligation to consultation or monitor consultation, please produce a copy of any and all correspondence or documentation concerning the same.

RESPONSE

a) through g) The OEB's Procedural Order No. 1 of August 13, 2018 made provisions for parties to "request any relevant information and material from the IESO in respect of the Addendum to the Updated Needs Assessment". The questions posed by BZA do not concern the Addendum and it is the IESO's view that they are therefore are beyond the scope of Procedural Order No. 1.

CCC INTERROGATORY 1

CCC-1

REF: EB-2017-0364, Exhibit K1.8, Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion, June 30, 2011, page 37.

Once in service, an expanded E-W Tie is expected to reduce congestion in the Northwest system by approximately 40%. Market congestion payments (CMSC) in the Northwest have averaged $40M per year over the last 9 years since market opening. Under the current market structure, an expanded E-W Tie could create savings of roughly $15M per year through congestion payment reduction. As this payment is borne by Ontario ratepayers, any reduction in CMSC payments would be a benefit to them. This benefit is not included in the cost-effectiveness analysis presented in Section 5.1.

REF: Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion, Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, June 29, 2018, (the "Addendum") pages 4-5.

The existing East-West Tie is one of the northern Ontario transmission interfaces currently subject to congestion, contributing to an increase in the average cost of energy. As a result of congestion on the East-West Tie and the downstream interfaces, low-cost energy from hydro facilities is sometimes bottled in the Northwest, leading to higher priced – and often higher-emitting – resources being dispatched in southern Ontario to meet Ontario's energy needs. The IESO used an energy dispatch model to estimate future congestion costs due to a delay to the in-service date of the E-W Tie Expansion; the model assumed median water levels. The estimated difference in energy production costs from delaying the in-service date of the E-W Tie Expansion is approximately $0.5 million (2017$) per year.

INTERROGATORY

The Council notes that in 2011 the Ontario Power Authority (the "OPA") forecast potential savings of roughly $15M per year through congestion payment reduction. In the Addendum the only reference to congestion related impacts is to an approximately $.5 million impact per year related to an estimated difference in energy production costs.

a) Please confirm that the IESO is no longer forecasting an impact related to a reduction in CMSC payments or other similar impacts related to the reduction in congestion in the North West System related to the East-West Tie (once in service) other than the $.5 million referred to in the Addendum. If confirmed, please describe the change in circumstances that has resulted in the elimination of the benefit related to congestion reduction that was quantified in the amount of $15M per year by the OPA in 2011; if not confirmed, please explain and quantify the impact.

RESPONSE

a) In the IESO's Addendum to the 2017 Updated Needs Assessment, the IESO did not quantify effects on CMSC payments of a delay to the in-service date of the East-West Tie Expansion (as was carried out in the 2011 report). Instead, the IESO estimated the increase in total energy cost per year as a result of a delay to the project. It is the IESO's view that this is a better measure for estimating the costs of congestion for three reasons:

1. First, CMSC is a market mechanism that reflects how overall congestion costs are "allocated" amongst market participants; it is not a measure of the overall cost of congestion.
2. Second, CMSC is a market mechanism (i.e. CMSC) that exists today for allocating congestion costs, but may not exist in the near future. As part of the IESO's Market Renewal initiative, the IESO is proposing to introduce locational marginal pricing which may eliminate CMSC payments. The IESO is currently planning to implement locational marginal pricing by 2022
3. Third, as described in the excerpt from the 2011 report, the estimate of $15 million in CMSC was derived based on historical CMSC payments. By contrast, the the IESO's estimate of the increase in total energy cost per year as a result of a delay to the project is based on modelling expected future conditions.

The IESO confirms that the $0.5 million per year increase in energy costs is the total expected energy cost impact of continued congestion in the northwest due to the delay of the East-West Tie Expansion.

NEXTBRIDGE INTERROGATORY 1

NextBridge-1

Reference: The IESO's June 29, 2018 Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion - Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date (hereinafter referred to as "IESO June 29, 2018 Report".)

INTERROGATORY

Provide all work papers, including the electronic/active version of all spreadsheets, models, analyses, input files and documents, used, relied upon, referenced and/or created in the development of the IESO June 29, 2018 Report.

RESPONSE

The IESO's Addendum to the 2017 Updated Needs Assessment relied on and was based on:

1) The analysis from the IESO's 2017 Updated Assessment for the Need for the East-West Tie Expansion ("IESO 2017 Needs Update Report") which determined the nature of the need in the years beyond 2018 as there had been no material changes, and
2) The costs information for incremental capacity, additional losses and foregone energy savings during the period of a delay.

For 1) the IESO carried out the following steps and analysis to determine the updated capacity need in the Northwest:

- Updated the demand outlooks and received comments/feedback from local stakeholders:
    - The residential and commercial sector demand outlook produced for the Northwest zone was updated by the IESO's load forecasting team, including the impact of conservation programs.
    - The IESO updated it's "likelihood factors" for identified mining developments in the Northwest based on conversations with customers and local stakeholders. One of four likelihood categories (Most Likely, Likely, Less Likely, Least Likely) was assigned to each potential Northwest mining project identified for development within the study period. Each likelihood category carries a probability factor which de-rates the peak load requirement of the potential mine depending on the likelihood of it advancing to commercial operation. The probability factors are adjusted based on the demand outlook (reference, high or low) and the aggregate load is converted to yearly energy profiles (8760 profiles).
    - The assumptions for other existing and forecast industrial loads were adjusted

based on conversations with customers and stakeholders.

- Updated generator information:
    - The IESO's most recent records of contracted and rate-regulated generation were used for the IESO 2017 Needs Update Report to inform the resource adequacy study.
- Updated estimates of hydroelectric capability and water condition probabilities:
    - The IESO used a data set including over 50 years of historical water flow at large hydroelectric generators in the Northwest to inform the characterization of these resources.
    - The resource adequacy assessment treated water conditions probabilistically. Based on the historical data set of water flow and data collected in IESO-administered markets, a range of water conditions and associated probabilities was developed.
- Reviewed limitations on the transmission system:
    - The IESO confirmed the interface limit of the existing East-West Tie used in the 2015 planning assessment.
- Completed a resource adequacy assessment and confirmed the forecast capacity need for each year in the study period:
    - The IESO used the GE-MARS tool[1] to conduct a resource adequacy assessment for the Northwest region.
    - The assessment probabilistically considered water conditions, the effect of weather on demand, fuel availability risks and generator outages. The GE-MARS model is used to estimate the probability of a supply shortfall resulting from these risks.
    - The capacity need identified is the amount of capacity that reduces the risk of a supply shortfall to an acceptable level, as measured by the loss-of-load expectation (LOLE) metric.

In the analysis for the IESO 2017 Needs Update Report, the IESO used UPLAN (a production cost/energy modelling tool) to model the system with and without the East-West Tie Expansion in service (as well as with and without the generation alternative) and compared system production costs and congestion impacts. These simulations were used as a basis for the foregone energy savings analysis.

For 2) the IESO carried out the following steps:

- To determine the projected incremental capacity cost, the IESO:

[1] GE-MARS is an energy modelling software tool which uses sequential Monte Carlo simulation to assess resource adequacy and calculate reliability indices.

  - Identified options that could provide incremental capacity. This was done based on knowledge of available and contracted system resources, past procurements (demand response), and information from past studies of the capability of interconnection facilities.
  - Applied the criteria outlined in the IESO's response to NextBridge Interrogatory 11 to determine a reasonable cost and associated uncertainty range.

- To determine the foregone energy savings, the IESO compared the overall system production costs for scenarios with and without the East-West Tie Expansion in-service, as described in the IESO's response to NextBridge Interrogatory 19.
- To determine an estimate cost of the additional transmission line losses associated with a delay to the in-service date of the East-West Tie Expansion, the IESO carried out the following analysis:
  - Developed an equation representing losses as a function of transfer rate based on the findings of a number of load flow studies using PSS/E ("loss factor equation").
  - Produced an energy simulation in UPLAN for both a case with today's East-West Tie (with the operating limit modelled) and a case with the East-West Tie Expansion (modelled as unconstrained). The hourly flow information for the East-West Tie interface was exported from UPLAN for both simulations along with the marginal unit cost in each hour for the case without the East-West Tie Expansion.
  - Applied the loss factor equation to both sets of hourly flow values to produce hourly losses for a case with and without the East-West Tie Expansion in service. The difference between the hourly losses represents the energy saved due to the East-West Tie Expansion. The energy saved in each hour was multiplied by the marginal cost for the hour. The sum of the costs of the additional energy required for all the hours in the year was determined to be representative of the continued cost of losses associated with a delay to the in-service date.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 2

NextBridge-2

Reference: The IESO's June 29, 2018 Report at 1, lines 4-7.

INTERROGATORY

Define what is meant by "reliability impacts".

RESPONSE

An impact to reliability is an impact on the IESO's ability to meet applicable ORTAC, NERC or NPCC planning standards.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 3

NextBridge-3

Reference: The IESO's June 29, 2018 Report at 1, lines 8-10.

INTERROGATORY

a) Identify all the categories of "additional costs" that were considered.

b) Identify any types or categories of costs that were considered, but not included in the Report.

RESPONSE

a) As outlined in the IESO's Addendum to the 2017 Updated Needs Assessment, the costs of incremental capacity, additional transmission line losses, and lost savings on energy productions costs that may be experienced due to a delay to the in-service date of the East-West Tie Expansion were considered. No additional costs beyond these were considered.

b) There were no additional costs that were considered but not included in the report.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 4

NextBridge-4

Reference: The IESO's June 29, 2018 Report at 1, lines 8-10.

INTERROGATORY

a) Explain in detail what is meant by "increased risks to system reliability."

b) Identify each risk to system reliability that was considered.

c) Identify each risk to system reliability that was intentionally not considered.

RESPONSE

a) Increased risks to system reliability refers to the increased probability of ORTAC, NERC or NPCC planning standards not being met, which means there is an increased probability of load in the Northwest being interrupted for longer time periods than allowed by these standards.

b) The risk to system reliability that was considered included inadequate supply capacity for the Northwest based on the assumptions in the IESO's 2017 Needs Update Report.

c) No risks were intentionally not considered.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 5

NextBridge-5

Reference: The IESO's June 29, 2018 Report at 1, lines 16-28.

INTERROGATORY

Please provide a copy of the referred to Ontario planning criteria.

RESPONSE

A copy of the Ontario Resource and Transmission Assessment Criteria (ORTAC) is included as Attachment 1 to this exhibit.

Page Intentionally Blank

PUBLIC

IMO_REQ_0041

REQUIREMENTS

Ontario Resource and Transmission Assessment Criteria

Issue 5.0

This document is to be used to evaluate long-term system *adequacy* and *connection assessments*

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This document may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the "Market Rules". To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

Document ID	IMO_REQ_0041
Document Name	Ontario Resource and Transmission Assessment Criteria
Issue	Issue 5.0
Reason for Issue	Released for Baseline 17.1
Effective Date	August 22, 2007

Document Change History

Issue	Reason for Issue	Date
1.0	First release	June 4, 2003
2.0	Issue released for Baseline 10.0	September 10, 2003
3.0	Name and logo changed to IESO	September 14, 2005
4.0	Released for Baseline 15.0	March 8, 2006
5.0	Revised for Baseline 17.1	August 22, 2007

Related Documents

Document ID	Document Title

Table of Contents

Table of Changes

Reference (Section and Paragraph)	Description of Change
Entire document	Name changed to Ontario Resource and Transmission Assessment Criteria. Defined terms were italicized. Document titles were reformatted as per section 1.4. Quotations were removed from words that are not documents.
Section 1	Clarified the purpose, scope and users of the document. Added conventions section.
Section 2	Clarified load modelling (sec 2.4) and contingency criteria (sec 2.7.1). Aligned section 2.7.1 with the criteria with NPCC document A-02 (section 5.0). Clarified study time periods, load forecasts and modelling, local area requirements, bulk power system and local area contingency studies.
Section 3	Clarified special protection systems (sec 3.4.1). Clarified how system conditions were to be modelled including generation dispatch, stability conditions, permissible control actions and special control systems. Changed to section 3.1.1 to 3.1 and corrected references to 3.1.1.
Section 4	Clarified P-V curves (sec 4.5.1). Clarified power transfer capability, pre-contingency voltage limits and voltage change limits, steady state voltage stability, lines and equipment loading and short circuit levels.
Section 5	Updated section heading and all references to be "Transmission Connection Criteria".
Section 6	Updated section heading and all references to be "Generation Connection Criteria". Clarified how transmission line ratings are calculated in the vicinity of wind farms.
Section 7	Created a new section titled " 7. Load Security and Restoration Criteria ". Clarified the effect of local generation when one element is out of service and when two elements are out of service. References to E-2 were deleted in section 7.2. Clarified control action criteria and application of restoration criteria.
Section 8	Created a new section titled "Resource Adequacy Assessment Criterion". Changed title of document to "Ontario Resource and Transmission Assessment Criteria"
Appendix E	Deleted
References	Added documents referred to within this document

1. Introduction

1.1 Purpose

The purpose of this document is to identify the technical criteria for use in the assessments of the *adequacy* and *security* of the *IESO-controlled grid* and to clarify how the *IESO* will apply the relevant *NPCC* and *NERC* standards and implement them within Ontario.

1.2 Scope

This document is to be used for assessing the current and future *adequacy* of the *IESO-controlled grid*, for conducting the *IESO's* 18-month outlooks, for identifying the need for system enhancements and for evaluating the effectiveness of planned generation and transmission enhancements. It does not identify operating or safety criteria.

1.3 Who Should Use This Document

This document is used by the *IESO* and may also be referred to by stakeholders and *market participants* to help them understand *IESO* criteria and further their *connection assessment* work.

1.4 Conventions

The standard conventions followed for market manuals are as follows:

- The word 'shall' denotes a mandatory requirement;
- Terms and acronyms used in this market manual including all Parts thereto that are italicized have the meanings ascribed thereto in Chapter 11 of the "Market Rules";
- Double quotation marks are used to indicate titles of legislation, publications, forms and other documents.

Any procedure-specific convention(s) shall be identified within the procedure document itself.

– End of Section –

2. Study Parameters and Contingency Criteria

This section is intended to provide guidance in carrying out the technical studies to assess the *adequacy* of the *IESO-controlled grid* in order to meet general load growth and *connection assessment* requirements, and to ensure that *reliability* is within standards. It also includes contingency criteria consistent with *NERC* and *NPCC* standards.

These study parameters must be applied on the basis of good utility practice and judgment, taking into account the particular circumstances and characteristics of the part of the *IESO-controlled grid* that is being studied.

This section includes study guidelines for: study period, base case, load levels, power transfer capability, area flow requirements, contingency based assessment and study conditions.

2.1 Study Purpose

The purpose of conducting studies is to identify system deficiencies and to establish the requirements for a connection proposal to ensure it satisfies *reliability standards*.

A comparison of the results of power flow studies under normal and *outage* conditions (with normal and *outage* power flows) will determine:

- the need date for new transmission investment in the *IESO-controlled grid* to maintain the *reliability* of supply within standards; or,
- the acceptability of a connection proposal for a *connection assessment*.

The sensitivity of the need date to load growth rate, resource variations (e.g. approved *connection assessments*) and related system developments should be investigated. The results of this investigation should normally be given in terms of a range of dates within which there is a high confidence level that the connection proposal is acceptable or that additional *facilities* or enhancements will be required.

2.2 Study Period

The study period depends on the purpose of the assessment. When checking the reliability of long term projects and plans the study period must go out beyond the in-service date and include various years between the start and end dates of the study.

- For *connection assessments* for proposed load developments, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of load forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *connection assessments* for generators, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of demand forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *connection assessments* for proposed *transmission* developments, the study period shall run from the planned in service date of the proposed *facility* up to 10 years into the future depending on the availability of load forecasts. Where the evaluation depends on factors or system developments beyond the 10 year study period, the study period may need to be extended farther into the future.

- For *NPCC* transmission reviews, the study period covers a 4 to 6 year look ahead period from the report date. These reviews are of three types: a comprehensive or full review, an intermediate or partial review and an interim review. Refer to *NPCC* document B-04, "Guidelines for *NPCC* AREA Transmission Reviews" for details.

- For *NPCC* resource adequacy reviews, the study period covers a 5 year look ahead period. These reviews are of two types: a comprehensive resource review and an annual interim review. Refer to *NPCC* document B-08, "Guidelines for Area Review of Resource Adequacy" for details.

Note that it is unnecessary to consider every year in the study period. The first and last years of the study period plus sufficient intermediate years to zero in on and bracket the critical year(s) is generally adequate.

2.3 Base Case

Master base cases are used as the starting point for all studies. The master base cases include all *connection assessment* projects that are approved, including those that did not require a formal *connection assessment* study. *Local area* details are added as appropriate. Information regarding base cases can be found on the *IESO's* Forecasts webpage.

The *IESO* Web site also provides firm and planned resource scenarios as described in each 18-Month Outlook.

Connection assessment studies are conducted using the master base cases. Long term assessment studies start with the master base cases and exclude less firm generation *connection assessment* projects per the planned resource scenario. The impact of adding approved *connection assessment* projects should be reviewed to identify if approved *connection assessments* improve or worsen any identified deficiency.

2.4 Load Forecasts and Load Modelling

The load levels used in the study shall be based on the latest forecast[1] consistent with the IESO's and the OPA's latest long-term forecast. Load forecast uncertainty should be taken into account by investigating the sensitivity of the need date to various items (e.g. higher and lower loads).

The summer or winter median growth forecast (based on normal weather) should be used depending on the peak loading conditions of the area being studied.

The sensitivity study should be done with high-growth extreme weather forecasts and low-growth normal weather forecasts, and with light load scenarios as required in order to stress the system. Under light load conditions, worst case ambient conditions should be assumed.

If a *connection assessment applicant* provides a detailed local forecast, that forecast should be used.

For *local area* assessments, the 18 month master base case should be modified to ensure the forecast is representative of the most recent peak load and power factors based on billing data. Local load should be modeled as accurately as possible and any local *embedded generator(s)* or large motor(s) should be included.

For assessment purposes the power factor is assumed to be 0.90 at the *defined meter point*. If an *embedded generator* is connected to a load bus, the 0.90 power factor is assumed with the generator out-of-service. In certain circumstances detailed load models may be required if they are expected to impact the *local area* performance.

Dispatchable load will be assumed to be consuming as required in order to stress the system.

Studies should be done with a load model representative of the actual load. For powerflow planning studies assessing the voltage stability of the bulk system, loads normally should be modelled as constant megavolt-amperes (MVA). In assessing voltage change limits and transient performance, a voltage dependent load model should be used. If specific information is not available, the load model in Ontario should be as indicated in the following table:

Static Load Models for Simulation

REAL POWER		**REACTIVE POWER**	
Constant Current	**Constant Impedance**	**Constant Current**	**Constant Impedance**
(%)	**(%)**	**(%)**	**(%)**
50	50	0	100

Thus, in Ontario, a load model of P=50, 50, Q=0, 100 (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$) should be used. The load models for neighboring areas should be consistent with load models used in Reliability First Corporation (RFC), Midwest Regional Organization (MRO), and *NPCC* studies.

[1] The IESO continues to produce 10-year demand forecasts using an econometric model. These forecasts are coordinated with OPA's multi-year end use forecasts and adjusted for Conservation and Demand Management (CDM).

2.5 Power Transfer Capability

A power transfer capability analysis should be performed throughout the study period taking into account the effects of planned *facilities*, the growth in loads, and the effects (if any), of various system generation patterns. The transfer limits should be determined for one or both directions of flow (as necessary).

With all transmission *facilities* in service, the power transfer capability is determined for the worst applicable contingency. Also, it will generally be necessary to determine the effects of seasonal variations (e.g., summer and winter line ratings) on the limits.

Generally, the transmission interface limits will be determined by one or more of the following post-contingency considerations:

- line and equipment loading must not exceed ratings,
- voltage declines must not exceed certain limits,
- machine and voltage angles must remain in synchronism, and
- voltages are stable (V-Q sensitivity is positive).

2.6 Local Area Requirements

Inter-area transmission is any circuit or group of transmission circuits interconnecting two areas of the *IESO-controlled grid*. Flows across the interface may either always be in one direction or in different directions at different times, in which case it may be necessary to consider each of the areas as the receiving area. The impact of *local area facilities* on inter-area transmission must be evaluated.

The magnitude and direction of future power flow requirements on the area studied should be determined for normal and contingency conditions. Peak, off-peak, and light load flow requirements should be considered.

With all transmission *facilities* in service (normal conditions), the schedule for generation in the receiving area should be based on the historically typical conditions. That is, for pre-contingency conditions, nuclear and run of river hydro-electric generation should be assumed at a level that is available 98% of the time. For example, on-peak conditions should be assessed with peaking hydro-electric generation plants, fossil plants and wind farms running at maximum output. Where *reliability* depends on local generation, sensitivity studies should be done to assess the impact of *outages* of local generation.

Load diversity and transmission losses should be given due consideration to ensure *facility* requirements are not overestimated.

2.7 Contingency-Based Assessment

The principal purpose of a system *adequacy*/*connection assessment* is to identify any areas where supply *reliability* may be at unacceptable risk. This could be due to a combination of factors such as load growth, load reduction, generation, or non-deliverability within a certain area.

The *IESO-controlled grid* must be planned with sufficient capability to withstand the loss of specified, representative and reasonably foreseeable contingencies at projected customer *demand* and anticipated transfer levels. Application of these contingencies should not result in any criteria violations, or the loss of a major portion of the system, or unintentional separation of a major portion of the system. The *IESO-controlled grid* shall be designed with sufficient capability to keep voltages, line and equipment loading within applicable limits for these contingencies

The *IESO*, as a member of *NPCC*, uses a contingency-based assessment to evaluate the *adequacy* and *security* of the bulk power system. The contingencies considered are identified in *NPCC* criteria A-02, "Basic Criteria for Design and Operation of Interconnected Power Systems". The *IESO* conducts studies with these contingencies applied throughout the *IESO-controlled grid*, assuming that *facilities* have not been designed to bulk power system standards, to test for the consequences. The *IESO* evaluates the study results to determine if a *facility* should be designated a bulk power system *facility*. If the consequence of the contingency has a significant adverse impact outside the *local area*, the *facilities* are deemed to be bulk power system *facilities* and must comply with *NPCC* criteria A-02, A-04, "Maintenance Criteria for Bulk Power System Protection" and A-05, "Bulk Power System Protection Criteria". *NPCC* Criteria are not applied in *local areas* where the consequence of faults or disturbances is well understood and restricted to a clearly defined set of *facilities* on the *IESO-controlled grid*.

NPCC extreme contingencies shall be assessed periodically in accordance with *Reliability* Coordinating Council criteria A-02, and guideline B-04, "Guideline for *NPCC* AREA transmission Reviews".

NPCC is in the process of developing the classification methodology for identifying the elements that constitute the bulk power system (reference *NPCC* A-10, "Classification of Bulk Power System Elements". The *IESO's* definition of the bulk power system will be consistent with *NPCC's* definition.

When conducting *connection assessments* or assessing system *adequacy*, various contingencies are applied to the *IESO-controlled grid* and their impact is evaluated. Different contingencies are evaluated for the bulk power system and *local areas*. For those parts of the *IESO-controlled grid* that are designated as bulk power system *facilities*, *NPCC* design criteria contingencies are applied, per Section 2.7.1. For those parts of the *IESO-controlled grid* that are designated as *local areas*, *local area* contingencies are applied, per Section 2.7.2.

In *local areas*, where the contingency propagates to a higher voltage level or causes a net load loss in excess of 1000MW, the *IESO* will apply the bulk power system contingencies described in section 2.7.1.

2.7.1 The Bulk Power System Contingency Criteria

In accordance with *NPCC* criteria A-02, the bulk power system portion of the *IESO-controlled grid* shall be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in this section. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that generation and power flows are adjusted between *outages* by the use of *ten-minute operating reserve* and where available, phase angle regulator control and HVdc control.

Stability of the bulk power system shall be maintained during and following the most severe of the contingencies stated below, with due regard to reclosing. The following contingencies are evaluated for the bulk power system portion of the *IESO-controlled grid*:

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.

b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent circuits of a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition is an acceptable risk and therefore can be excluded.

c. A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with delayed fault clearing (This contingency covers a breaker failure).

d. Loss of any element without a fault.

e. A permanent phase-to-ground fault on a circuit breaker with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.) Note that this condition covers the blind spot on a breaker or on a bus section between a free standing current transformer (CT) and a breaker. It is included for completeness and is not intended to be more onerous than c) above (e.g. neither a stuck breaker nor a protection system failure need be considered for this type of contingency on account of the low probability of such an occurrence, therefore, there would normally be no reason to actually test for this condition).

f. Simultaneous permanent loss of both poles of a direct current bipolar *facility* without an ac fault.

g. The failure of a circuit breaker to operate when initiated by an *SPS* following: the loss of any element without a fault; or a permanent phase-to-ground fault, with normal fault clearing on any transmission circuit, transformer or bus section.

The bulk power system portion of the *IESO-controlled grid* shall be designed in accordance with these criteria and the *IESO's* local voltage control procedures and criteria, which shall be coordinated with adjacent *control areas*[2]. Adequate reactive power resources and appropriate controls shall be installed in the *IESO-controlled grid* to maintain voltages within normal limits for predisturbance conditions, and within applicable *emergency* limits for the system conditions that exist following the contingencies specified above.

Line and equipment loadings shall be within normal limits for predisturbance conditions and within applicable *emergency* limits for the system conditions that exist following the contingencies specified above.

The *IESO-controlled grid* shall be designed to ensure that equipment capabilities are adequate for fault current levels with all transmission and *generation facilities* in service for all potential operating conditions. Procedures established to manage fault levels shall be coordinated with adjacent areas and regions[2].

[2] Language and accountabilities used in NPCC A-2 is evolving. Terms such as control areas, areas, and regions should be interpreted broadly to include the meaning originally intended in A-2, until it is revised.

2.7.2 Local Area Contingencies

For *local areas* the *IESO-controlled grid* must exhibit acceptable performance following:

a. the loss of an element without a fault, and

b. a phase-to-phase-to-ground fault on any generator, transmission circuit, transformer, or bus section with normal fault clearing.

In the non bulk power system, the contingencies studied and the acceptability of involuntary load interruptions are dependent on the amount of load impacted. Typically only single-element contingencies are evaluated. The *IESO* defines a single-element as a single zone of protection. Double element contingencies are evaluated as per section 2.7.1.

2.7.3 Extreme Contingencies

NPCC criteria A-02 recognizes that the bulk power system can be subjected to extreme contingencies. Even though the probability of these situations is low, *NPCC* criteria states that analytical studies shall be conducted to determine the effect of certain extreme contingencies. In the case where an extreme contingency assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies must be conducted, and measures may be utilized where appropriate to reduce the likelihood of such contingencies or to mitigate the consequences indicated in the assessment of such contingencies.

2.7.4 Extreme System Conditions

The bulk power system can be subjected to abnormal system conditions with a low probability of occurring such as peak load conditions resulting from extreme weather conditions with applicable ratings of electrical elements or fuel shortages. An assessment to determine the impact of these conditions on expected steady-state and dynamic system performance shall be done in order to obtain an indication of system robustness or to determine the extent of a widespread adverse system response. After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions.

2.8 Study Conditions

The system load and generation conditions under which the contingencies are assumed to occur are chosen on a deterministic basis to represent the reasonable worst case scenario. For loadflow and transient stability studies, the system should be studied with various pre-contingency conditions that stress the system. Various contingencies should then be evaluated to identify the most limiting contingencies and conditions. Typical sets of system conditions to evaluate in the study of the bulk power system and *local areas* are shown below. Not all conditions need to be evaluated. Studies should start with the one or two most stressful system conditions. If no deficiency is identified then no additional study is required. If a deficiency is identified, sensitivity studies should be done to further define the timing and magnitude of the deficiency. These additional conditions for long term assessments may include modifying the master base case to include approved connection approvals.

Various interface transfer levels should be considered to stress the system as required to uncover deficiencies.

Sample System Conditions to Evaluate in Studies for the Bulk Power System

Weather/Load	Generation	Transmission	Contingencies per Section 2.7.1
Median growth extreme weather	All in service	All in service	All
Median growth normal weather	2 units out of service	All in service	All
Median growth normal weather	All in service	1 element out of service	All
Low growth normal weather	All in service	All in service	All
Light load normal weather	Reduced *dispatch* as required	All in service	All

The purpose of the analysis is to identify the consequence of various scenarios up to two single contingencies, but not necessarily the worse possible contingencies under the worst load and ambient conditions.

Sample System Conditions to Evaluate in Studies for Local Areas

Weather/Load	Local Generation	Local Transmission	Contingencies per Section 2.7.2
Median growth extreme weather	Up to 2 local units out of service	All in service	All
Median growth extreme weather	All in service	Any one element out of service	All
Light load normal weather	Various scenarios	Various scenarios	All
Low growth normal weather	All in service	All in service	All

– End of Section –

3. System Conditions

The specific load and generation conditions and assumptions, applicable stability conditions, and permissible use of control actions for the area being studied are identified in the following sections.

3.1 Generation Dispatch

Generation is to be *dispatched* as required in order to stress the system so as to identify limitations of the *transmission* transfer capability.

3.2 Exports and Imports

All exports and imports should be taken into account to achieve the conditions of section 3.1. The pre-contingency level of the transfer selected should be based on the existing and projected *interconnection* capability. Combinations of maximum transactions coincident with high internal power flows should be considered in order to stress the import interface and to ensure studies evaluate the full range of power flow scenarios. In addition, the effect of bilateral *interconnection* assistance up to the tie-tine capability should be studied with all transmission *facilities* in service. Post-contingency tie flows that are different from the scheduled flows on phase-shifted ties or greater than the pre-contingency interface flow on unregulated ties may be permitted before adjustment provided they are within applicable limits (generally the 15 minute rating).

3.3 Stability Conditions

3.3.1 Contingencies

The system shall remain stable during and after the most severe of the contingencies listed in 2.7.1 and 2.7.2, with due regard to reclosing as per *NPCC* criteria A-02.

3.3.2 General Guidelines

The *NPCC* A-02 criteria do not stipulate the use of margin on transient stability limits. However, the *IESO* criteria require that all stability limits should be shown to be stable if the most critical parameter is increased by 10%. This is to account for modeling errors, metering errors and variations in *dispatch*.

The 10% increase can be simulated by generation or load changes even beyond the forecast load or generation capabilities provided it does not lead to invalid results. Negative values of local load is preferable to increasing local generation beyond its maximum capability.

3.4 Permissible Control Actions

Following the occurrence of a contingency, the following control actions may be used to respect the loading, voltage decline, and stability limits referenced in this document:

- Generation Redispatch
- Automatic tripping of generation (generation rejection)
- Trip circuits open to change flow distributions
- Trip or redispatch *dispatchable loads*
- Switch reactors and/or capacitors out (switching in of capacitors in locations that are especially sensitive to voltage changes is to be done only in such a manner as to ensure minimal impact on customers, e.g., using independent pole operation (IPO) breakers)
- Operate phase shifters

In addition to the above control actions, automatic or manual tripping of *non-dispatchable load* may be considered for certain contingencies with one or more transmission elements out-of-service. Generally, *facilities* for the automatic tripping of load will only be acceptable as a stop gap measure to increase the power transfer capability across a bulk transmission interface to cope with temporary deficiencies.

The control actions that are permissible are shown below:

Permissible Control Actions Following Contingency

System Condition Prior to Contingency	**Permissible Control Actions Following Contingency**
All elements in service	• Generation Redispatch • Load Redispatch • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions
One or more transmission elements out of service	• Generation redispatch including transactions • Generation Rejection • Capacitor Switching • Reactor Switching • Open circuits to change flow distributions • Load Rejection

3.4.1 Special Protection System

A *special protection system* (*SPS*) is defined as a protection system designed to detect abnormal system conditions and take corrective action(s) other than the isolation of faulted elements. Such action(s) may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. The *NPCC* A-02 criteria provide for the use of a *SPS* under normal and *emergency* conditions.

A *SPS* shall be used judiciously and when employed, shall be installed consistent with good system design and operating policy. A *SPS* associated with the bulk power system may be planned to provide protection for infrequent contingencies, for temporary conditions such as project delays, for unusual combinations of system demand and outages, or to preserve system integrity in the event of severe outages or extreme contingencies. The reliance upon a *NPCC* type I *SPS* for *NPCC* A-2 design criteria contingencies with all transmission elements in service must be reserved only for transition periods while new transmission reinforcements are being brought into service. A *SPS* associated with the non-bulk portion of the power system may be planned to provide protection for a wider range of circumstances than a *SPS* associated with the bulk system.

The decision to employ a *SPS* shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. The requirements of *SPSs* are defined in *NPCC* criteria A-05, and in NPCC criteria A-11, "Special Protection System Criteria". With all transmission elements in service, continued reliance on a *SPS* is a trigger for considering additional transmission.

A *SPS* proposed in a *connection assessment* must have full redundancy and separation of the communication channels, and must satisfy the requirements of the *NPCC* Type I *SPS* criteria to be considered by the *IESO*.

Automatic Tripping of Generation (Generation Rejection)

Automatic tripping of generation via Generation Rejection Schemes (G/R) is an acceptable post-contingency response in limited circumstances as specified below in section 7.3, Control Action Criteria. Arming of G/R may be acceptable for selected contingencies provided the G/R corrects a *security* violation and results in an acceptable operating state.

– End of Section –

4. Pre and Post Contingency System Conditions

This section identifies the acceptable pre-and post-contingency response on the *IESO-controlled grid*. Criteria include:

- Power Transfer Capability
- Pre Contingency Voltage Limits
- Voltage Change Limits
- Transient Voltage Criteria
- Steady State Voltage Stability
- Congestion
- Line and Equipment Loading
- Short Circuit Levels

If studies indicate that any criterion in this section is not met, the *IESO* will either notify the *IESO-administered market* of a system inadequacy or inform the *connection assessment* proponent that the submitted proposal is not acceptable (i.e. that the proposal must be re-designed).

4.1 Power Transfer Capability

To evaluate the impact of a *connection assessment* on power flow across an interface, it is important to consider:

- The impact on the power flow caused by the introduction of a new limiting contingency (new elements introduce new contingencies); and
- The impact on power flow distribution over the interface (transfer capability) caused by the introduction of new *facilities* which change power flow distribution.

New or modified connections to the *IESO-controlled grid*, for example a new generator, may increase congestion on transmission *facilities* but will not be permitted to lower power transfer capability or operating *security limits* by 5% or more. This will be assessed on a case by case basis. The following are examples of changes that could affect the transfer capability or operating *security* limits:

- an increase in load or generation greater than or equal to 20 MVA;
- where the connectivity of the transmission system is changed and a new contingency is created;

- where the electrical characteristics of generation facilities are changed by greater than or equal to 5%, or exceed accepted design standards and tolerances, or are not in conformance with Appendix 4.2 of the Market Rules;
- where the electrical characteristics of a transmission facility change by greater than or equal to 10%;
- where the transfer capability is reduced by more than 5%; or
- where a new or modified SPS is proposed

4.2 Pre-Contingency Voltage Limits

Under pre-contingency conditions with all *facilities* in service, or with a critical element(s) out of service after permissible control actions and with loads modeled as constant MVA, the *IESO-controlled grid* is to be capable of achieving acceptable system voltages. The table below indicates the maximum and minimum voltages generally applicable. These values are obtained from Chapter 4 of the "Market Rules", and CSA standards for distribution voltages below 50 kV.

Nominal Bus Voltages

Nominal Bus Voltage (kV)	**500**	**230**	**115**	**Transformer Stations, e.g. 44, 27.6, 13.8 kV**
Maximum Continuous (kV)	550	250	127*	106%
Minimum Continuous (kV)	490	220	113	98%

* Certain buses can be assigned specific maximum and minimum voltages as required for operations. In northern Ontario, the maximum continuous voltage for the 115kV system can be as high as 132kV.

- Transmission equipment must be able to interrupt fault current for voltages up to the *maximum continuous rating.*
- Transmission equipment must remain in service, and not automatically trip, for voltages up to 5% above the maximum continuous rating, for up to 30 minutes, to allow the system to be re-*dispatched* to return voltages within their normal range.

Transformer stations must have adequate under-load tap-changer or other voltage regulating *facilities* to operate continuously within normal variations on the *transmission system* and to operate in *emergencies* in accordance with transmission voltage ranges as listed in the table in section 4.3.

In general, system pre-contingency voltages used in planning studies should approximate existing system voltage profiles under similar load and generation conditions.

Voltages below 50kV shall be maintained in accordance with CSA 235 by the *transmitter* and/or *distributor*.

4.3 Voltage Change Limits

With all planned *facilities* in service pre-contingency, system voltage changes in the period immediately following a contingency are to be limited as follows:

Nominal Bus Voltage (kV)	500	230	115	Transformer Station Voltages		
				44	27.6	13.8
% voltage change **before** tap changer action	10%	10%	10%	10%	10%	10%
% voltage change **after** tap changer action	10%	10%	10%	5%	5%	5%
AND within the range						
Maximum* (kV)	550	250	127	112% of nominal		
Minimum* (kV)	470	207	108	88% of nominal		

*The maximum and minimum voltage ranges are applicable following a contingency. After the system is redispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages identified in section 4.2.

Before tap-changer action (immediate post-contingency period) a constant MVA load model can be used. If the voltage change exceeds the limits identified above, a voltage dependent load model should be used (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$). After tap-charger action a constant power load model should be assumed (e.g. the load will return to its pre-contingency level). In areas of the system where it is known that post-contingency voltages will remain depressed after tap-changer and other automatic corrective actions, or in situations where special control actions are proposed (e.g., blocking of under-load tap-changers), the use of variable loads in the longer term post-contingency period may be acceptable.

In cases where voltage rises are a possibility (e.g., islanded generators), transient stability tests should be carried out as a check to ensure that realistic reactive additions are appropriate and that customer equipment will not be exposed to excessive voltages after the transient post-contingency period. The occurrence of a voltage rise for loss of a system element is rare but voltage rises after reclosure operations, especially where capacitor or reactor switching are involved, are relatively common and should be checked. Voltage rises should not result in bus voltages higher than the maximum values indicated in the above table. Not only is equipment damage a concern at such high voltages but, in addition, it may not be safe to carry out breaker switching operations to reduce the voltages to acceptable levels. Capacitor breakers at locations where excessive voltages are possible should be designed for appropriately higher operating voltages.

4.3.1 Reactive Element Switching Change

Reactive devices should be sized to ensure that voltage declines or rises at *delivery point* buses on switching operations will not to exceed 4% of steady state rms voltage before tap changer action using a voltage dependent load model (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$).

4.3.2 Capacitive Element Switching Change

Capacitive devices include HV capacitors, LV capacitors, SVCs, series capacitors, and synchronous condensers.

Capacitive devices should be sized to ensure that voltage declines or rises at *delivery point* buses on switching operations will not exceed 4% of steady state rms voltage for line switching operations per Chapter 4 of the "Market Rules". This 4% is based on load flows before tap changer action using a voltage dependent load model (e.g. $P \propto V^{1.5}$, and $Q \propto V^2$).

4.4 Transient Voltage Criteria

In cases where protection or control coordination may be an issue, or where significant induction motor load is present, time domain simulations should be conducted to assess the dynamic voltage performance. These simulations should cover a time frame in which ULTCs operate (<30 seconds) and should include modeling of devices which affect voltage stability (such as induction motors, ULTCs, switched shunts, generator field current limiters, etc). Per section 3.3.1, due regard should be given to reclosure operations in the simulation.

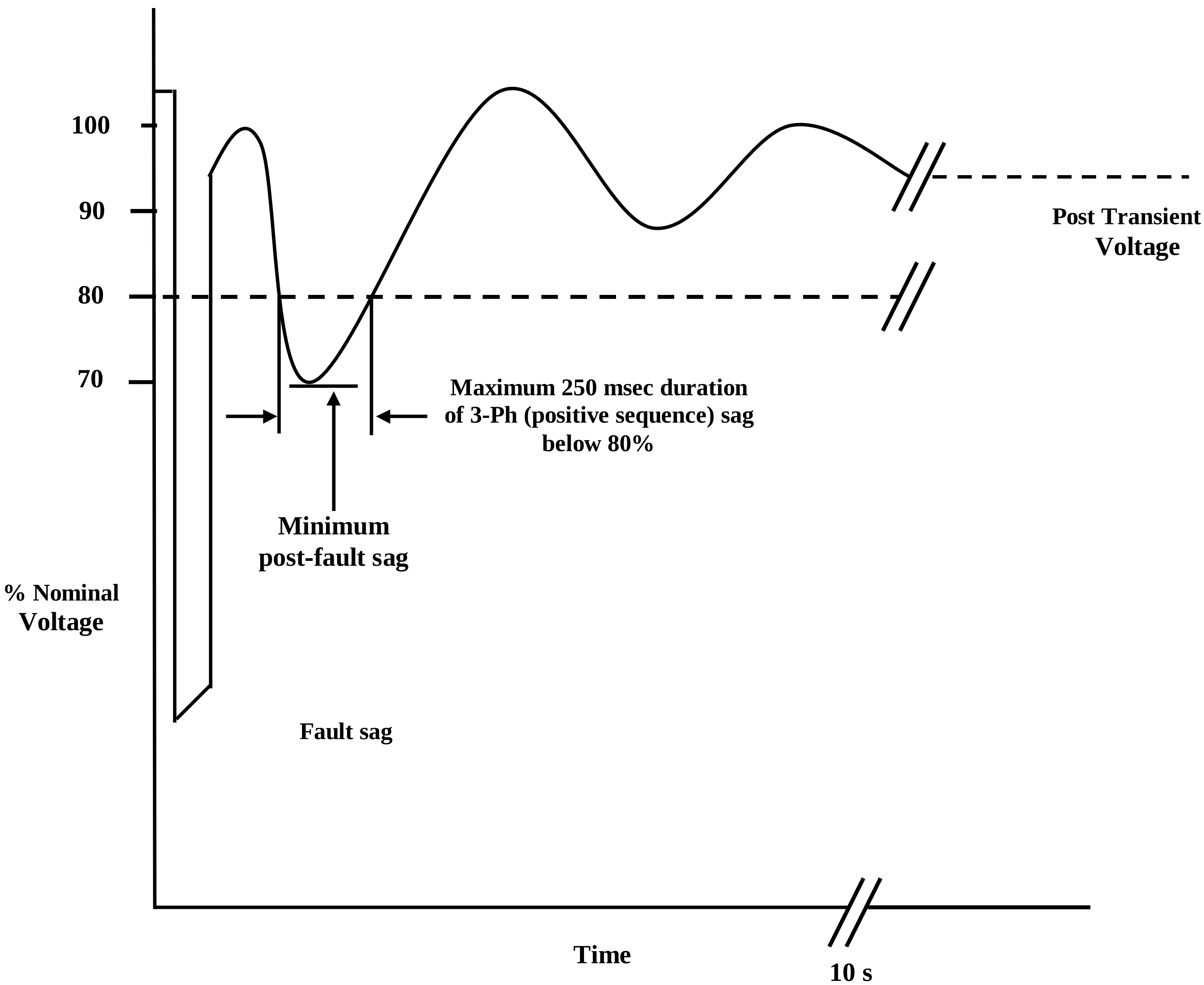
For transient voltage performance, studies should be done with a load model representative of the actual load. If that information is not available, the standard voltage dependent load model of P=50, 50, Q=0, 100 is to be used (see section 2.4 Load Forecasts and Load Modelling).

This criterion is not intended to be used as a standard of utility supply to individual customers, nor used for transmission and distribution protection design. Rather it is intended to avoid uncontrolled, significant load interruption that may lead to unintended *transmission system* performance. The starting voltage, sag and duration of post-fault transient undervoltages are a measure of the system strength, and its ability to recover promptly.

The following transient voltage criteria are to be used to evaluate system performance. The *IESO* will conduct periodic review of the IEEE standards and relevant literature to monitor the need to revise this section.

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not remain below 80% of nominal voltage for more than 250 milliseconds within 10 seconds following a fault. Specific locations or grandfathered agreements may stipulate minimum post-fault positive sequence voltage sag criteria higher than 80%. IEEE standard 1346-1998 supports these limits.

Transient Voltage Sag Criteria



Mitigation options include high-speed fault clearing, *special protection systems*, field forcing, transmission reinforcements and transmission interface transfer limits.

While the determination of whether a transient stability test is stable or unstable is generally straightforward, issues such as transient load shakeoff, high voltage tripping of capacitors, and undamped oscillatory behaviour in the post-transient period should be considered using the following guidelines:

- occasional tests should be run out to about thirty seconds - first swing stability does not guarantee transient stability;
- high voltage swings will generally be considered acceptable unless the magnitude or duration of the high voltage swing could be sufficient to cause capacitor tripping. Typical maximum voltage and duration of swing to avoid damage to and tripping of high voltage capacitors are identified

below. The magnitude of the high voltage swing must be less than the capacitor breaker rating multiplied by the factor in the following table for the duration indicated.

Duration	Maximum Permissible Voltage (Multiplying Factor To Be Applied to Rated RMS Voltage)
½ cycle	3.00
1 cycle	2.70
6 cycles	2.20
15 cycles	2.00
1 second	1.70
15 seconds	1.40

4.5 Steady State Voltage Stability

Adequate voltage performance under 4.4 above does not guarantee system voltage stability. Steady state stability is the ability of the *IESO-controlled grid* to remain in synchronism during relatively slow or normal load or generation changes and to damp out oscillations caused by such changes.

The following checks are carried out to ensure system voltage stability for both the pre-contingency period and the steady state post-contingency period:

- Properly converged pre- and post-contingency powerflows are to be obtained with the critical parameter increased up to 10% with typical generation as applicable;
- All of the properly converged cases obtained must represent stable operating points. This is to be determined for each case by carrying out P-V analysis at all critical buses to verify that for each bus the operating point demonstrates acceptable margin on the power transfer as shown in the following section; and
- The damping factor must be acceptable (the real part of the eigenvalues of the reduced Jacobian matrix are positive).

The following sections provide more information on damping factor, use of P-V curves to identify stability limits, and dynamic voltage performance simulations.

4.5.1 Power – Voltage (P-V) Curves

To generate the P-V curve, loads should be modeled as constant MVA. In specific situations, if good data is available, voltage dependent loads and tap-changer action may be modeled in detail to assess the system voltage performance following the contingency and automatic equipment actions but before manual operator intervention.

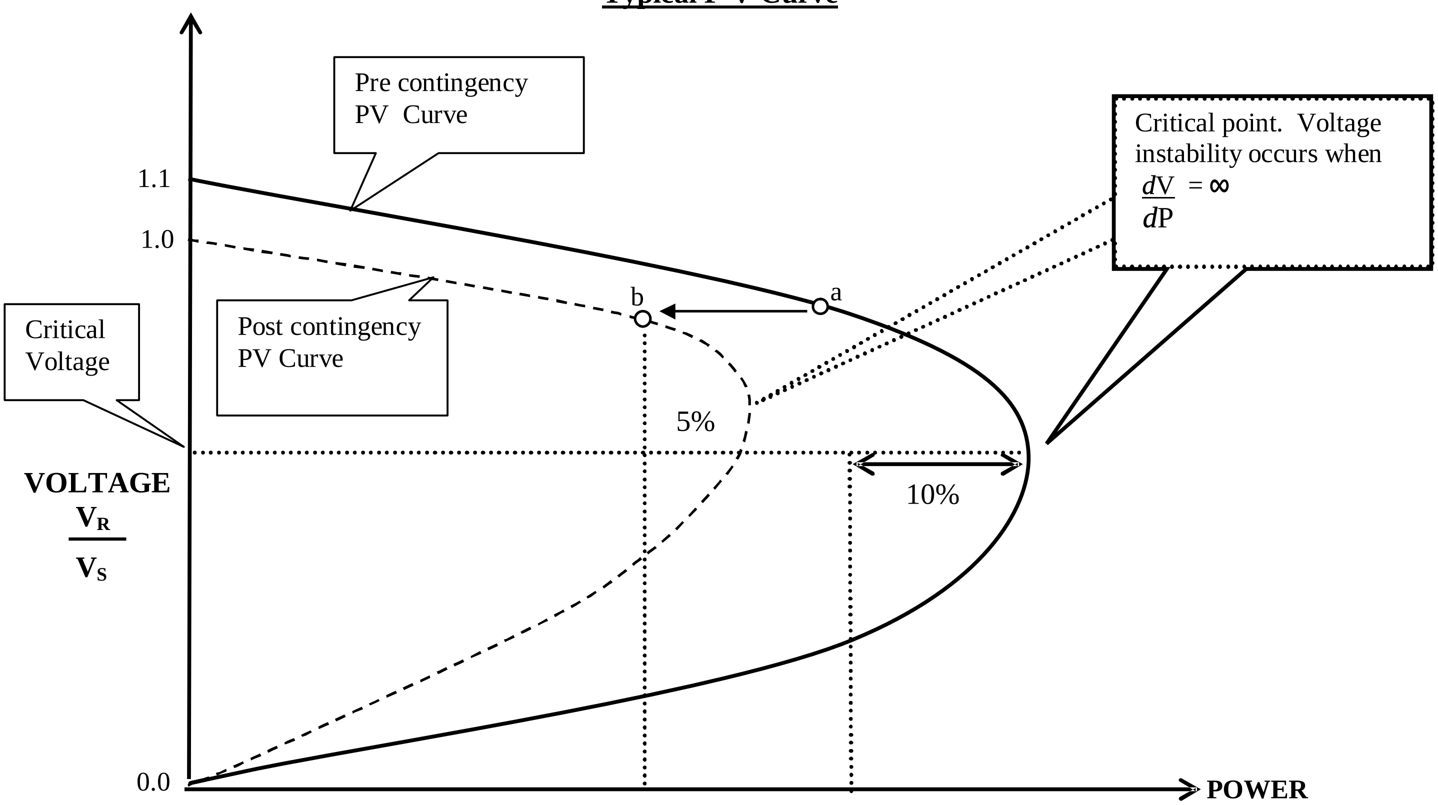
Power flow programs can be used to generate a P-V curve. In certain situations it may be desirable to manually generate a P-V curve to take into account specific remedies available.

A sample P-V curve is shown below. The critical point of the curve, or voltage instability point, is the point where the slope of the P-V curve is vertical. As illustrated, the maximum acceptable pre-contingency power transfer must be the lesser of:

- a pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve, and
- a pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve

The P-V curve is dependent on the power factor. Care must be taken that the worst case P-V curve is used to identify the stability limit.

Typical P-V Curve



Maximum Power
Voltage Stability Limit

4.5.2 Damping Factor

The damping factor provides a measure of the steady-state stability margin of a power system. The damping factor can be derived from an eigenvalue state-space model of the power system. The damping factor (x) is:

$$\xi = \frac{-\delta}{\sqrt{\delta^2 + \omega^2}}$$

where δ and ω are the real and imaginary parts of the critical eigenvalue. If δ is negative, the oscillations will decay. Where the eigenvalues are not available δ and ω may be measured from time domain simulations by assuming that the oscillations are exponentially damped sinusoids in a second order system.

The damping factor determines the rate of decay of the amplitude of the oscillation. The following table provides pre and post contingency damping factor requirements.

Acceptable Damping Factors

System Condition	Damping Factor
Pre-Contingency	> 0.03
Post-contingency[1]	> 0.00
Post-Contingency[2]	> 0.01
Following Repreparation of the system[3]	> 0.03

1. Before automatic intervention
2. Following automatic intervention. Studies should assume **NO** manual intervention
3. Following all permissible control actions identified in section 3.4

For critical cases, there should be evidence of strong damping of system oscillations within about 10 seconds, otherwise, simulations should be run out to about 20 seconds and all modes of oscillations should show adequate damping behaviour. For swings characterized by a single dominant mode of oscillation, the damping can be calculated directly from the oscillation envelope; a 15% decrement between cycles is required to meet the damping factor criteria.

4.6 Congestion

Congestion is the condition under which the trades that *market participants* wish to implement exceed the capability of the *IESO-controlled grid*. It usually requires the system operator to adjust the output of generators, decreasing it in one area to relieve the constraint and to increase it in another to continue to meet customer *demand*.

For long term *adequacy* assessments, congestion should be flagged where observed. Congestion is flagged as the amount of time that interface flows exceed 100% of their limit where the limit has been increased by the use of applicable *SPSs*. Locational pricing data, where available, may be used to assess historical congestion costs.

4.7 Line and Equipment Loading

4.7.1 General Guidelines

All line and equipment loading limits, the limited time associated emergency ratings and the ambient conditions assumed in determining the ratings are defined by the equipment owner. Long-term emergency ratings are generally a 10-day limited time rating for transformers, and a continuous or 50 hour /year rating for transmission circuits. Short-term emergency ratings are generally 15-minute or 30-minute limited time ratings for transformers and transmission circuits. For each assessment, the applicable ratings will be confirmed with the equipment owner.

4.7.2 Loading Criteria

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

It is assumed that for the bulk power system, loading conditions and control actions are available to reduce the loading to the long-term emergency rating or less within 15 minutes.

Circuit breakers, current transformers, disconnect switches, buses and all other system elements must not be restrictive.

The ratings of tie lines are governed by agreements between the *facility* owners. The criteria to direct operation of the lines are governed by agreements between the system or market operators.

4.8 Short Circuit Levels

Short circuit studies are to be carried out with all existing *generation facilities* in service and with all *connection assessments* that have been approved, including those that did not require a formal *connection assessment* study. System voltages are to be assumed to be at the maximum acceptable system voltage identified in Section 4.2. The latest information from neighbouring systems that may have an impact on short circuit studies (including *NPCC* SS-38 and *NERC* MMWG representation) is to be used to define relevant *interconnection* assumptions. Short circuit levels must be within the maximum short circuit levels and duration specified in the Ontario Energy Board's (OEB's) "Transmission System Code".

No margin is used when comparing the short circuit value to *facility* ratings.

The *IESO* will accept make before break switching operations that temporarily increase fault levels beyond breaker interrupting capability as long as affected equipment owners are willing to accept the risk and its consequences.

4.9 Station Layout

Guidance on transformer and switching station layout is provided in Appendix B. The guidelines provide an acceptable way towards meeting the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

– End of Section –

5. Transmission Connection Criteria

The term "transmission connection" is applied to any *facility* that establishes or modifies a connection to the *IESO-controlled grid* such that a *connection assessment* is required.

5.1 New or Modified Facilities

New or modified *facilities* must satisfy all *NERC* standards, Regional *Reliability* Council Criteria, and the requirements of the OEB's "Transmission System Code", the "Market Rules" and associated standards, policies, and procedures.

New or modified *facilities* must not materially reduce the level of *reliability* of existing *facilities*. Specifically:

- *facilities* within a common zone of protection, such as line taps or bus sections, must be built to meet or exceed the affected *transmitter's* standards prevailing at the time of construction;
- the *security* and dependability of protection equipment that forms a common zone of protection, or of protections that are required to operate in a coordinated fashion, must be of a standard of *reliability* that is equal to or higher than the *reliability standards* specified in the OEB's "Transmission System Code" prevailing at the relevant time;
- *facilities*, such as line taps, that significantly increase the line length and thereby its exposure to faults, may be required to use circuit breakers and separate zones of protection to limit the additional exposure to existing connections; and
- new or modified connections must not materially reduce the existing transfer capability of the *IESO-controlled grid*, and must not impose additional restrictions on the deployment of existing *connection facilities*.

5.2 Effect on Existing Facilities

New or modified connections must not materially reduce the load-meeting capability of existing *facilities.*

New or modified connections must not restrict the capability of existing *generation facilities* or loads to deliver to or receive power from the *IESO-controlled grid.*

Where there would be insufficient transmission capability to deliver the maximum registered capacity to the *IESO-controlled grid* while recognizing applicable contingency criteria:

- the proposal must be re-designed, e.g. the maximum registered capacity must be reduced to a level that can be delivered;
- the transmission *facilities* must be refurbished or replaced; or
- *special protection systems (SPS)*, in limited circumstances, may be utilized to mitigate the effects of contingencies on the transmission *facilities*.

– End of Section –

6. Generation Connection Criteria

Transmission to incorporate new generation is defined as those new circuits that connect the generator to the *IESO-controlled grid*, plus any reinforcements to the *IESO-controlled grid* required as a direct and sole result of the new generation. With the new generation at its maximum output, all load levels should be considered.

6.1 Voltage Change

The loss of a generating *facility* due to a single-element contingency involving any element upstream of the generator bus (e.g. line or step-up transformer) should respect the voltage change criteria in section 4.3.

6.2 Wind Power

- For the purposes of *transmission system adequacy* and *connection assessments*, wind powered generators are to be treated as *non-dispatchable* (intermittent) units which are operating up to their maximum output.
- For *connection assessments*, transmission line ratings will be calculated using 15km/h winds, instead of the typical 4km/h, within the vicinity of the wind farm and, with the approval of the *transmission* asset owner, out to a 50 km radius.

Guidance on technical requirements related to wind turbine performance and wind farm station layout is provided in Appendix C. The guidelines provide a design that satisfies the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

As the *IESO* gains more experience with the operating characteristics of wind powered generators, the above criteria may be revised.

6.3 Synchronous Generation

Transmission *facilities* for incorporating new generation must meet the requirements of section 5. Guidance on technical requirements related to synchronous generator performance, station layout, and connection to the *IESO-controlled grid* is provided in Appendix D. The guidelines provide a design that satisfies the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

6.4 Station Layout

Guidance on transformer and switching station layout is provided in Appendix B. The guidelines provide an acceptable way towards meeting the contingency criteria of section 2.7. However, other configurations and station layouts that meet those criteria are also acceptable.

– End of Section –

7. Load Security and Restoration Criteria

The long-term *transmission system* planning criteria below establish default levels of load *security* and load restoration. The application of a lower level of load *security* may be acceptable in the non bulk portions of the *IESO-controlled grid* provided the bulk power system adheres to *NERC* and *NPCC* standards. Different criteria may be used for the facilities beyond the load side of the *connection point* to the *transmission system* (notionally the defined point of sale).

7.1 Load Security Criteria

The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.

With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

With any one element out of service[3], equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario.

With any two elements out of service[4], voltages must be within applicable *emergency* ranges, equipment loading must be within applicable short-term *emergency* ratings and transfers must be within applicable *emergency* condition stability limits. Equipment loading must be reduced to the applicable long-term *emergency* ratings in the time afforded by the short-time ratings. Planned load *curtailment* or load rejection exceeding 150MW is permissible only to account for local generation outages. Not more than 600MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 600MW load interruption limit reflects the established practice of incorporating up to three typical modern day distribution stations on a double-circuit line in Ontario.

[3] For example, after a single-element contingency with all transmission elements in service pre-contingency.
[4] For example, after a double-element contingency will all transmission elements in service pre-contingency or after a single-element contingency with one transmission element out of service pre-contingency.

7.2 Load Restoration Criteria

The *IESO* has established load restoration criteria for high voltage supply to a *transmission customer*. The load restoration criteria below are established so that satisfying the restoration times below will lead to an acceptable set of *facilities* consistent with the amount of load affected.

The *transmission system* must be planned such that, following design criteria contingencies on the *transmission system*, affected loads can be restored within the restoration times listed below:

a. All load must be restored within approximately 8 hours.

b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately 4 hours.

c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within 30 minutes.

These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7.3 Control Action Criteria

The deployment of control actions and *special protection systems* must not result in material adverse effects on the bulk system.

The *transmission system* may be planned such that control actions such as generation re-dispatch, reactor and capacitor switching, adjustments to phase-shifter and HVdc pole flow, and changes to inter-Area transactions may be judiciously employed following contingencies to restore the power system to a secure state.

The reliance upon a *special protection system* must be reserved only for exceptional circumstances, such as to provide protection for infrequent contingencies, temporary conditions such as project delays, unusual combinations of system *demand* and *outages*, or to preserve system integrity in the event of severe *outages* or extreme contingencies.

Transmission expansion plans for areas that may have a material adverse effect on the interconnected bulk power system must not rely on *NPCC* Type I *special protection systems* with all planned transmission *facilities* in service.

7.4 Application of Restoration Criteria

Where a need is identified, for example via the *IESO's* outlooks or via the OPA's IPSP, *market participants* and the applicable *transmitter* will be notified of the need for a deliverability study.

Transmission customers and *transmitters* can consider each case separately taking into account the probability of the contingency, frequency of occurrence, length of repair time, the extent of hardship caused and cost. The *transmission customer* and *transmitter* may agree on higher or lower levels of *reliability* for technical, economic, safety and environmental reasons provided the bulk power system adheres to *NERC* and *NPCC* standards.

7.5 Exemptions to the Restoration Criteria

Where the *transmission customer(s)* and *transmitter(s)* agree that satisfying the security and restoration criteria on *facilities* not designated as part of the bulk system is not cost justified, they may jointly apply for an *exemption* to the *IESO*. In applying for this *exemption*, *transmission customer(s)* and *transmitter(s)* will identify the conditions (generally the timing and load level) under which they plan to satisfy the criteria. *IESO* will assess these on a case-by-case basis and grant the *exemption*, allowing a lower level of *reliability*, unless there is a material adverse effect on the *reliability* of the bulk power system.

End of Section

8. Resource Adequacy Assessment Criterion

8.1 Statement of Resource Adequacy Criterion

To assess the *adequacy* of resources in Ontario, the *IESO* uses the *NPCC* resource adequacy design criterion from *NPCC* A-02:

> "Each Area's probability (or risk) of *disconnecting* any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [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."

8.2 Application of the Resource Adequacy Criterion

The *IESO* uses the General Electric Multi-Area Simulation (MARS) computer program to determine the reserve margin required to meet the *NPCC* resource adequacy criterion. A detailed load, generation, and transmission representation for 10 zones in Ontario is modeled in MARS. Simple representations are used for the five external *control areas*[2] to which Ontario *connects*.

The reserve margin is expressed as a percent of *demand* at the time of the annual peak where the LOLE is at or just below 0.1 days per year. A reserve margin calculated on this basis represents the minimum acceptable reserve level needed to meet the *NPCC* resource adequacy criterion. At least once per year, *IESO* will calculate the required reserve margin at the time of annual peak for the next five years and will *publish* this value.

For operational planning purposes, just meeting the *NPCC* criterion is considered sufficient since frequent forecast updates combined with significant *outage* flexibility, external economic supply potential and the availability of *emergency* operating procedures have historically provided sufficient "insurance" against residual supply risk.

For capacity planning purposes, where longer term decisions must be made, additional reserves to cover residual uncertainties and project delays may be appropriate. Also, the *IESO* does not consider *emergency* operating procedures for longer term capacity planning because the relief provided by these measures is intended for dealing with *emergencies* rather than being used as a surrogate resource. Regular triggering of *emergency* operating procedures rather than developing appropriate resources could lead to the erosion of these options through overuse. The extent to which all uncertainty is covered becomes an economic decision which should be guided by the *NPCC* criterion.

8.3 Resource Assumptions

The Ontario system has a resource mix comprised of a variety of fuel types. Assumptions about resource availability vary by fuel type. Generally, resource availability forecasts are based on median assumptions. A complete description of the resource assumptions used in the *IESO's adequacy* assessments can be found in the methodology document entitled, "Methodology to Perform Long Term Assessments". This document is *published* quarterly with the release of the 18-Month Outlook Resource Adequacy Assessments.

End of Section

Appendix A: IESO/NPCC/NERC Reliability Rule cross-reference

IESO/NPCC/NERC Reliability Rule Cross-Reference

Section	Ontario Criteria	NPCC Criteria	NERC Standard
Resource *Adequacy*	Available *Capacity Reserve* Margin Requirement	A-2	TPL-005, 006; MOD-016 to MOD-021, 024, 025
Transmission Capability Planning **Bulk Power System**	Thermal Assessment	A-2	TPL-003; FAC-001, 002
	Voltage Assessment	A-2	
	Stability Assessment	A-2	
	Extreme Contingency Assessment	A-2	TPL-004
Transmission Capability Planning **Non Bulk *Local Areas***	Thermal Assessment		TPL-003; FAC-001, 002
	Voltage Assessment		
	Stability Assessment		
	Supply Deliverability Level		TPL-004

– End of Section –

Appendix B: Guidelines for Station Layout

This Appendix provides a guide to desirable configurations. Variations from this guide are permissible provided that such variations comply with the criteria of sections 2.7 and 4.

The specification of station layout requires consideration of the number of breakers required to trip all infeeds to a fault. Increasing the number of breakers to clear a fault results in the relaying systems becoming more complex and increases the chance of failure to clear all infeeds to the fault.

It is not practical to calculate mathematically the optimum balance of complexity, *reliability* and cost in specifying station layout. Therefore, a review of existing practices has been made and compiled as a guide to show the maximum complexity that should normally be permitted in design of station layout or switching connections for transformers or circuits.

In general, the specification of station layout and the number of breakers needed to trip to clear faults should take into account the following:

- probability of failure
- *reliability* studies of the layout
- effect on the *IESO-controlled grid*
- nature and size of the load affected
- typical duration of a failure
- operating efficiency

B.1 OEB's Transmission System Code

Any new connection or modification of an existing station layout must meet the requirements of the "Market Rules" and the OEB's "Transmission System Code".

The OEB's "Transmission System Code" specifies that all customers must provide an isolating *disconnect* switch or device at the point or junction between the *transmitter* and the customer. This device is to physically and visually open the main current-carrying path and isolate the Customer's *facility* from the *transmission system*. Details are provided in Schedule F of the OEB's "Transmission System Code".

Schedule G of the OEB's "Transmission System Code" specifies that a high-voltage interrupting device (HVI) shall provide a point of isolation for the generator's station from the *transmission system*. The HVI shall be a circuit breaker unless the *transmitter* authorizes another device.

B.2 Analysis of System Connections

The key factors that must be considered when evaluating a switching or transformer station include:

- *Security* and quality of supply
  Relevant criteria are presented in section 4.
- Extendibility
  The design should allow for forecast need for future extensions if practical.
- Maintainability
  The design must take into account the practicalities of maintaining the substation and associated circuits. It should allow for elements to be taken out of service for maintenance without negatively impacting *security* and quality of supply.
- Operational Flexibility
  The physical layout of individual circuits and groups of circuits must permit the required operation of the *IESO-controlled grid*.
- Protection Arrangements
  The design must allow for adequate protection of each system element
- Short Circuit Limitations
  In order to limit short circuit currents to acceptable levels, bus arrangements with sectioning *facilities* may be required to allow the system to be split or re-connected through a fault current limiting reactor.

The contingencies evaluated in assessing proposed station layout *adequacy* will be those outlined in section 2.7. The *IESO* will analyze the effect of various contingencies on the *adequacy* and *security* of the *IESO-controlled grid*. The *IESO* will also ensure that the proposed configuration allows for routine maintenance *outages* with minimal exposure to load interruption from subsequent contingencies. For example, for *facilities* classed as bulk power system, the *IESO* will examine the following contingencies for the proposed station layout:

- Fault on any element with delayed clearing because of a stuck breaker
- Maintenance *outage* on a breaker or bus followed by a single-element contingency

The resulting *IESO-controlled grid* performance must meet the criteria in section 4. As the *IESO-controlled grid* develops, the criteria under which a particular station layout is assessed may change (e.g. a *local area* station may become a bulk power system station).

The *IESO* will then evaluate the amount of load interrupted by single-element contingencies (or double circuit contingencies depending on the load level) with the proposed station layout". For example a *local area* switching station layout would be reviewed to ensure that a single-element or double circuit contingency would not result in an interruption that exceeds the criteria in section 7.1.

Evaluations of modifications to existing *facilities* will take into account the lower level of flexibility and layouts will be evaluated on the extent they meet the assessment criteria.

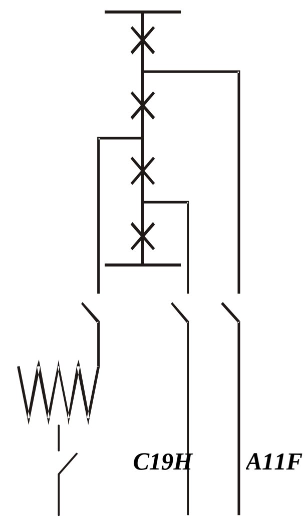
B.3 General Requirement's For Station Layouts

This section identifies general requirements for all station layouts based on *good utility practice* and operational efficiency. Acceptable system performance will dictate the acceptability of any proposed layout. This section provides the electrical single line diagram and does not reflect physical layouts. See section B.4 for information on physical layout.

B.3.1 "Breaker-And-A-Third" Layouts

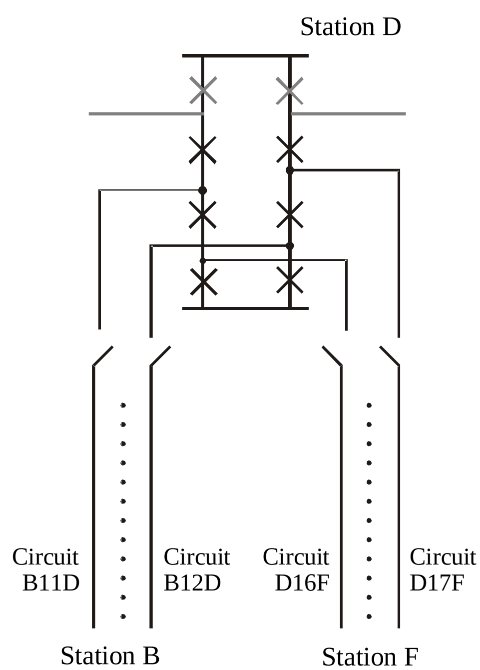
In "breaker-and-a-third" layouts the ideal location for autotransformers and generators is in the middle of the diameter as shown.

It is desirable to have one element (one autotransformer or one line) per position.



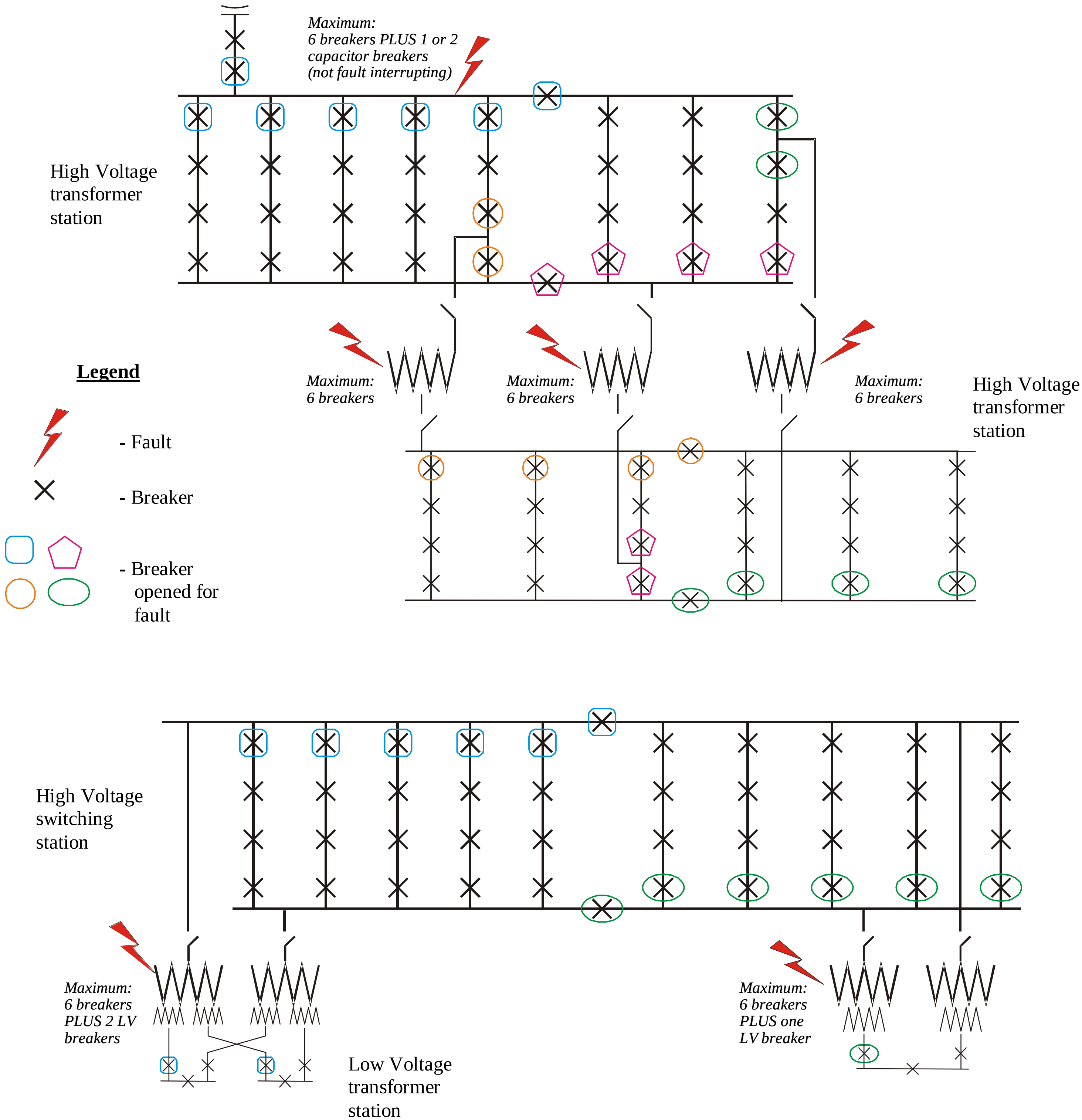
B.3.2 Bus Balance

The ideal arrangement for a double circuit line is to terminate each circuit on different diameters positioned so that there is maximum flexibility and *security* for a variety of fault and operating scenarios.



B.3.3 Maximum Breakers

Station layout should be such that a maximum of 6 High Voltage (500kV, 230kV and 115kV) and up to 2 capacitor or 2 Low Voltage breakers are needed to trip following any fault (operation of the capacitor breaker does not involve interruption of fault current). The following layouts illustrate these rules.



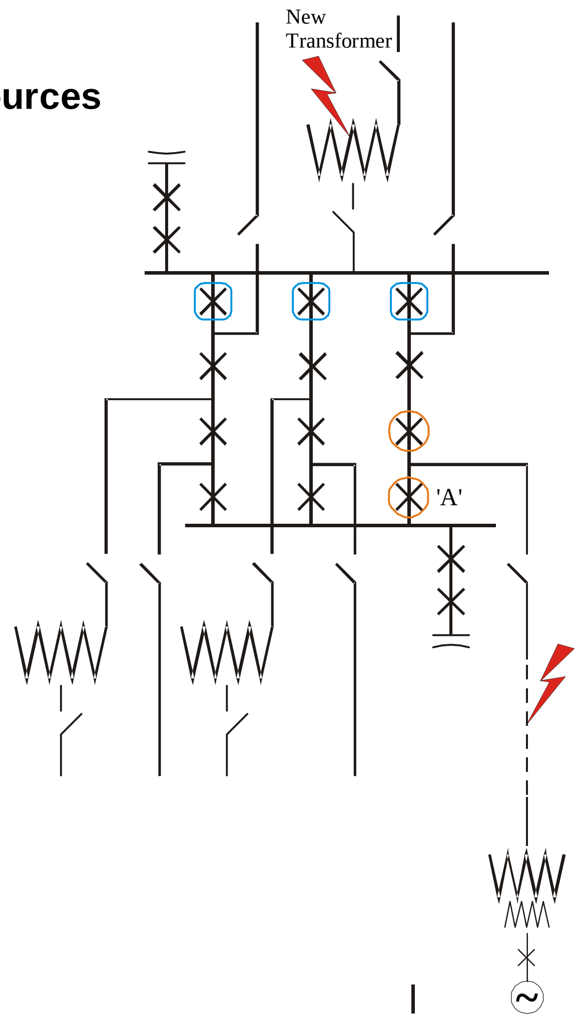
B.3.4 Separation of Reactive Power Sources

The goal of a good station layout is to minimize the effect of a contingency. Thus a contingency should result in the fewest possible number of elements removed from service.

In this vein, only one supply element should be connected directly to a bus. The intent is that a single contingency not result in the loss of two VAR sources.

For example, when terminating a new autotransformer, generator, circuit, or capacitor bank onto a bus, a single element contingency should not result in the loss of the autotransformer or line and the simultaneous loss of the capacitor bank or generator. (It would be acceptable to connect a step-down transformer and capacitor bank to the same bus.)

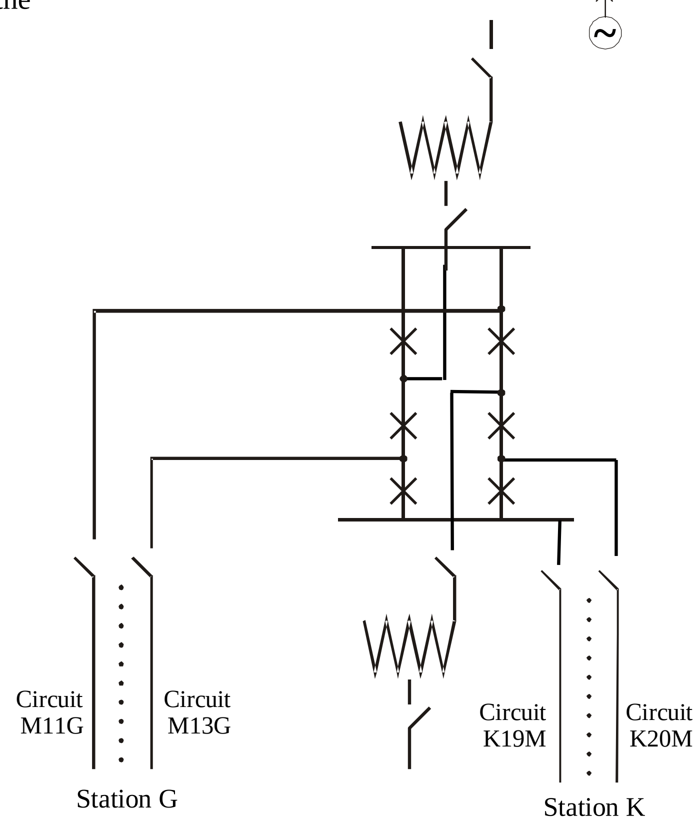
Per B.3.1, the ideal location of a generator is in the centre of a diameter (where the autotransformers are connected on the layout shown). The generator termination at the location shown is not ideal. A single-element contingency with breaker failure would result in the simultaneous loss of the generator and capacitor bank. To determine the acceptability of the layout shown it would be necessary to conduct a transmission assessment to class the *facility* as either bulk power system or local and then to evaluate the performance of the *IESO-controlled grid* for the appropriate contingencies.



B.3.5 Ring Bus

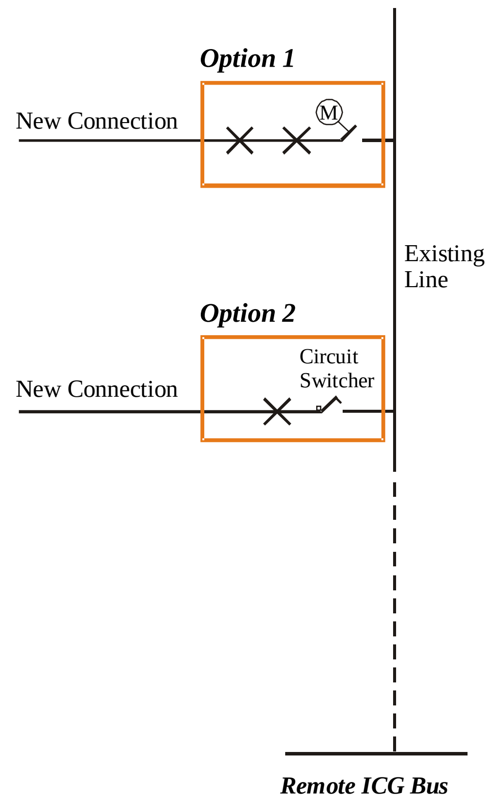
A minimum of three diameters is desired. Alternatively if a ring bus is temporarily unavoidable, the station should be laid out for the future addition of another diameter.

During periods when breakers are out-of-service for maintenance, ring buses can impose significant operational constraints. The layout shown provides one way to optimize the layout of a ring bus and minimize the adverse effect of maintenance.



B.3.6 Connections Without Transfer Trip

Where the *connection point* to the *IESO-controlled grid* is sufficiently remote that transfer trip is impractical, either of the two options shown would be acceptable.

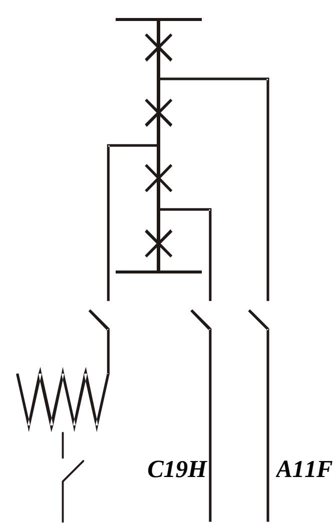


In Option 1, a line fault would initiate tripping of both breakers simultaneously, thereby addressing concerns about possible breaker failure if only a single breaker were used. This arrangement must include a motorized *disconnect* to provide 'physical' isolation of the new line from the *IESO-controlled grid*.

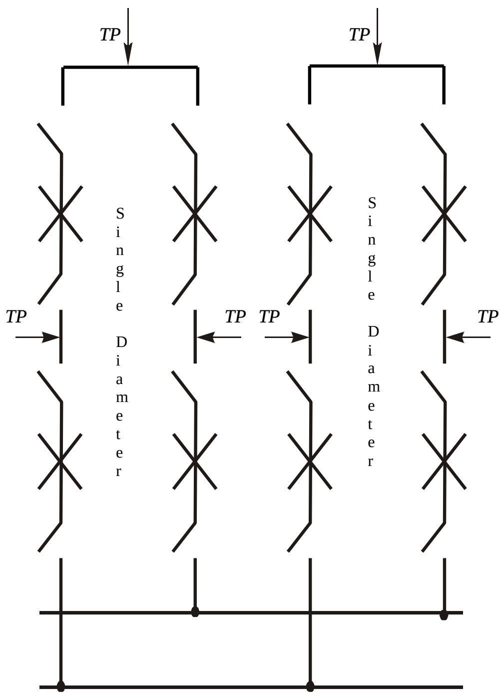
In Option 2, a line fault would initiate simultaneous operation of the single breaker and the circuit switcher. The integral *disconnect* switch of the circuit switcher would provide the required 'physical' isolation of the new line from the *IESO-controlled grid*.

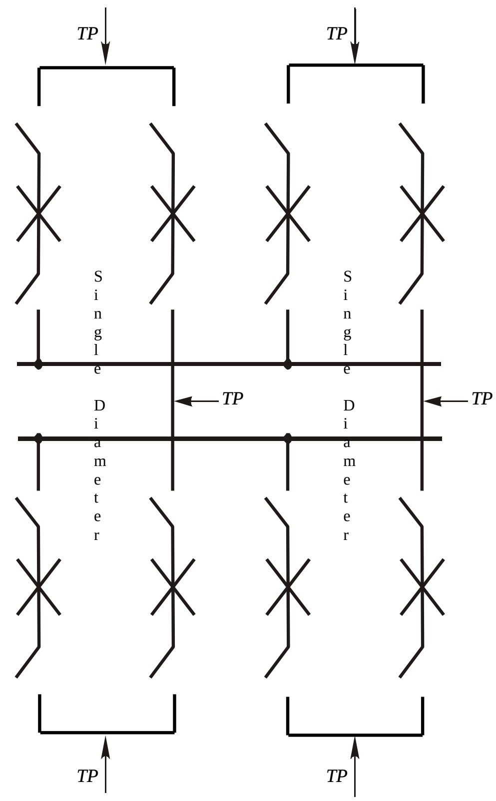
B.4 Physical Station Layouts

The electrical single line diagram of a "breaker-and-a-third" arrangement is shown. Typical physical layouts for "breaker-and-a-third" follow.



Typical Physical Arrangement for a Breaker-and-a-Third Layouts





TP = Termination Point for a transmission element such as a circuit, transformer, etc.

Overhead connections omitted for clarity

– End of Section –

Appendix C: Wind Farms Connection Requirements

The following is intended to clarify the requirements for connection to the *IESO-controlled grid* of wind-generation proposals which are aimed at ensuring that the *reliability* of the system is preserved. This short list does not relieve proponents from any *market rule* obligation. *Transmitter* and *distributor* requirements are separate and are not addressed herein.

The key factors that must be evaluated when performing a *connection assessment* of a wind farm are:

1. Equipment must be suitable for continuous operation in the applicable transmission voltage range specified in Appendix 4.1 of the "Market Rules". Equipment must also be able to withstand over-voltage conditions during the short period of time (not more than 30 minutes) it takes to return the power system to a secure state. Plant auxiliaries must not restrict *transmission system* operation.

2. Generating units do not trip for contingencies except those that remove generation by configuration. This requires adequate low and high voltage ride through capability. If generating units trip unnecessarily, they will require enhanced ride-through capability to prevent such tripping or the *IESO* may restrict operation to avoid these trips.

3. Recognized contingencies within the wind-*generation facility*, except for transmission breaker failures, must not trip the connecting transmission circuit(s).

4. Induction generators are required to have the reactive power capabilities described in Appendix 4.2 Reference 1 of the "Market Rules". Induction generating units injecting power into the *transmission system* are required to have the same reactive capabilities as synchronous units that have similar apparent power ratings. They are required to have the capability to inject at the *connection point* to the *IESO-controlled grid* approximately 43.6 MVAr for every 90 MW of active power (0.9 power factor at the low voltage terminals of the *connection point*). The requirement to provide the entire range of reactive power for at least one constant transmission voltage limits the impedance of the connection between the generating units and the *transmission system* to about 13% impedance on the generator's rated output base. Generating units not injecting power into the *transmission systems* must be able to reduce reactive flow to zero at the point of connection and must have similar reactive capabilities as units connected to the *transmission system*. The *IESO* may require any reactive power deficiencies of *facilities* injecting into the *transmission system* to be corrected by reactive compensation devices.

   - For wind turbine technologies that have dynamic reactive power capabilities described in 4.2 Reference 1 of the "Market Rules", additional shunt capacitors may be required to offset the reactive power losses over the wind farm collection system that are in excess of those allowed by the "Market Rules".

   - For wind turbine technologies that do not have dynamic reactive power capabilities described in 4.2 Reference 1 of the "Market Rules", dynamic reactive compensation (static var compensator) equivalent to the "Market Rules" requirement must be installed. In addition, shunt capacitors may be required to offset the reactive power losses that are in excess of those allowed by the "Market Rules", over the wind farm collection system.

5. *Facilities* shall have the capability to regulate voltage as specified by the *IESO*. Operation in any other mode of *regulation* (e.g. power factor or reactive power control) shall be subject to *IESO* approval.

6. *Facilities* shall be installed to participate in any *special protection system* identified by the *IESO* during the CAA process. In most cases, this will be generation rejection and the associated telecommunication *facilities*.

7. Generating units will meet the voltage variation and frequency variation requirements described in Appendix 4.2 Reference 2 and Reference 3 of the "Market Rules".

8. Real-time monitoring must be provided to satisfy the requirements described in Appendix 4.15 and Appendix 4.19 of the "Market Rules".

9. *Revenue metering* must be provided to satisfy the Market Rule requirements. No commissioning power will be provided until the *revenue metering* installation is complete.

10. The *facility* does not increase the duty cycle of equipment such as load tap changing transformers or shunt capacitors beyond a level acceptable to the associated *transmitter* or *distributor*.

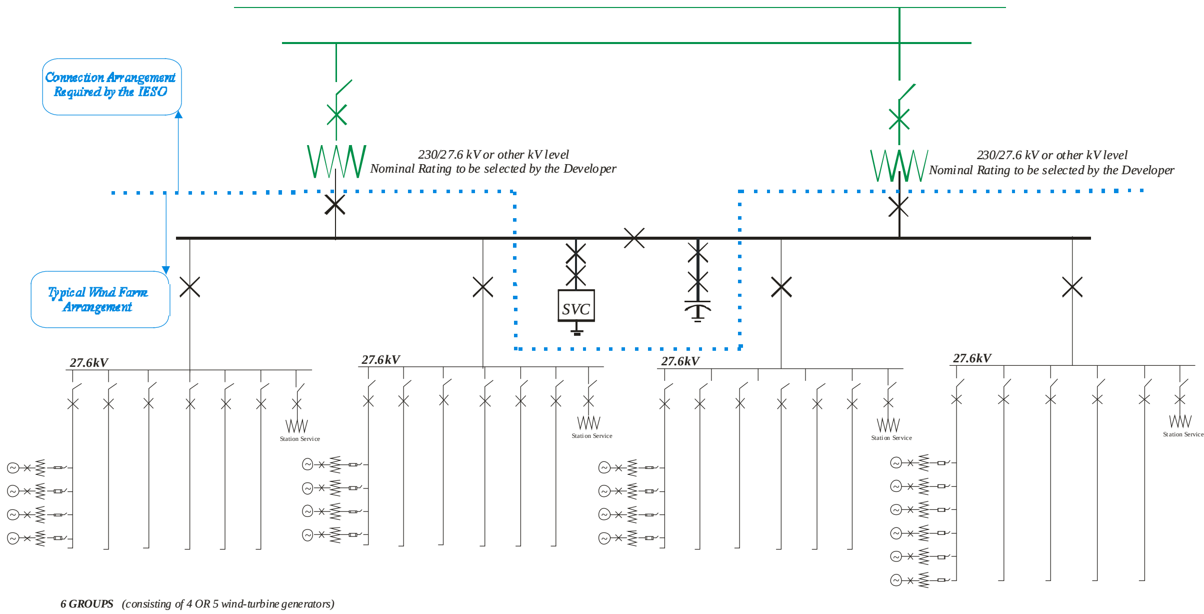
11. Line taps and step-up transformers connect to both circuits of a double-circuit-line (figure attached). The *facility* must be designed to balance the loading on both circuits of a double-circuit line.

12. Equipment must be designed so the adverse effects of failure on the *transmission system* are mitigated. This includes ensuring all transmission breakers fail in the open position.

13. Equipment must be designed so it will be fully operational in all reasonably foreseeable ambient conditions. This includes ensuring that certain types of breakers are equipped with heaters to prevent freezing.

14. The equipment must be designed to meet the applicable requirements of the OEB's "Transmission System Code" or the OEB's "Distribution System Code" in order to maintain the *reliability* of the grid. They include requirements identified by the *transmitter* for protection and telecommunication *facilities* and coordination with the exiting schemes. The protection systems for equipment connected to the *IESO-controlled grid* must be duplicated and supplied from separate batteries.

15. Disturbance monitoring equipment capable of recording the post-contingency performance of the *facility* must be installed. The quantities recorded, the sampling rate, the triggering method, and clock synchronization must be acceptable to the *IESO*.



Typical Configuration

Appendix D: Synchronous Generation Connection Requirements

The following summarizes the requirements for connection to the *IESO-controlled grid* of single-cycle or combined-cycle generation proposals of medium to large size which are aimed at ensuring that the *reliability* of the system is preserved. This short list does not relieve proponents from any m*arket rule* obligation. This document may be used by *market participants* to help them understand *IESO* criteria and further their *connection assessment* work.

Transmitter and d*istributor* requirements are separate and are not addressed herein. The Proponent is expected to follow other approvals processes to ensure the other aspects of *reliability* such as detailed equipment design, environmental considerations, power quality, and safety are properly addressed.

Generating Unit Performance

Excitation System

The requirements for exciters on *generation unit* rated at 10 MVA or higher are listed in Reference 12 of Appendix 4.2 in the "Market Rules" as follows:

- A voltage response time not longer than 50 ms for a voltage reference step change not to exceed 5%;
- A positive ceiling voltage of at least 200% of the rated field voltage, and
- A negative ceiling voltage of at least 140% of the rated field voltage.

In addition, the requirements for power system stabilizers (PSS) are described in Reference 15 of Appendix 4.2:

- Each synchronous generating unit that is equipped with an excitation system that meets the performance requirements described above shall also be equipped with a power system stabilizer. The power system stabilizer shall, to the extent practicable, be tuned to increase damping torque without reducing synchronizing torque.

Governor

Reference #16 of Appendix 4.2 of the "Market Rules" requires that every synchronous generator unit with a name plate rating greater than 10 MVA or larger be operated with a speed governor, which shall have a permanent speed droop that can be set between 3% and 7% and the intentional dead band shall not be wider than ± 36 mHz.

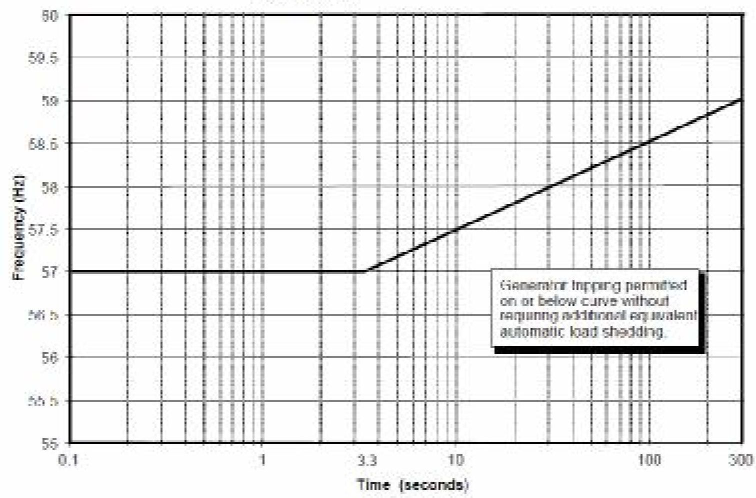
Automatic Voltage Regulator

Reference #13 of Appendix 4.2 of the "Market Rules" requires each synchronous generating unit to be equipped with a continuously acting *automatic voltage regulator* (*AVR*) that can maintain the terminal voltage under steady state conditions within ±0.5% of any voltage set point. Each synchronous *generation unit* shall regulate voltage except where permitted by the *IESO*.

Generator Underfrequency Performance

Reference #3 of Appendix 4.2 of the "Market Rules" requires that generating *facilities* be capable of operating continuously at full power for a system frequency range between 59.4 to 60.6 Hz. In accordance with *NPCC* criteria A-03, "Emergency Operation Criteria", generators shall not trip for under-frequency system conditions for frequency variations that are above the curve shown below. However, if this cannot be achieved, and if approved by the *IESO*, then automatic load shedding equivalent to the amount of generation to be tripped must be provided in the area. This criterion is required to ensure the stability of an island, if formed, and to avoid major under-frequency load shedding in the area.

Figure 1 - Standards for setting underfrequency trip protection for generators



<u>Generation Facility Connection Options</u>

The *IESO*, in its review of the various generation projects that propose to connect to the *IESO-controlled grid*, has developed typical connection arrangements for generation developments. Variations to the typical connection arrangements may be accepted by the *IESO* provided that *reliability* criteria are met and that the *connection assessment* studies prove that the system is not adversely affected. Connection of *generation facilities* larger than 500 MW that propose to use arrangements that are typical for the developments under 500 MW may be accepted subject to *IESO* approval.

Generation Facilities Rated between 250 MW and 500 MW

All projects rated between 250 MW and 500 MW are required to connect to two circuits (where available) and as a minimum provide one of the connectivity arrangements shown in Figure 1, 2 or 3. Station arrangements that connect two like elements next to each other separated by only one breaker should be avoided.

The configurations shown in Figure 1 and Figure 2 are suitable for coupled gas and steam turbines pairs.

- A contingency associated with one of the transmission lines will be cleared at the terminal stations and by the breaker on the corresponding generator line tap. If the post-contingency rating of the remaining line permits, the *facility* can remain connected to one circuit.

- A bus-tie breaker failure condition will send transfer trip to the line tap breakers and the entire *facility* will be tripped off. If the *IESO's* assessment indicates that tripping the entire generating *facility* will have a negative impact on the system then the *IESO* will recommend alternative connection arrangements.
- For the configuration in Figure 1, a contingency associated with one of the step-up transformers or a generator unit will be cleared by opening the bus-tie breaker and the HV synchronizing breaker.
- The configuration in Figure 2 is more economical because it allows the connection of two units via one step-up transformer but is less reliable since a contingency associated with one step-up transformer results in the loss of two generating units.
- For an *outage* associated with one of the HV breakers the entire *generation facility* could remain connected unless limited by equipment ratings, voltage, or stability.

For the connectivity shown in Figure 3:

- A contingency associated with one of the transmission lines will be cleared at the terminal stations and the corresponding breakers in the ring bus. If the post-contingency rating of the remaining line permits, the *facility* can remain connected to one circuit.
- An HV breaker failure contingency could trip two generating units or a line and a generating unit. If *IESO's* assessment indicates that tripping two generating units will have a negative impact on the system then the *IESO* will require either additional breakers to be installed or the size of the development to be reduced to an acceptable level.
- For an *outage* associated with one of the HV breakers the entire *generation facility* could remain operational unless limited by equipment ratings, voltage, or stability.

In addition the *generation facilities* will have to comply with the OEB's "Transmission System Code" requirements and other protection system requirements established by the *transmitter*.

<u>Generation Facilities Rated Above 500 MW</u>

All projects rated above 500 MW are required to connect to at least two circuits and provide one of the connectivity arrangements shown in Figure 4 or Figure 5. Station arrangements that connect two like elements next to each other separated by only one breaker should be avoided.

The full switchyard arrangement shown in Figure 4 is required when large generating *facilities* propose to connect to a main transmission corridor of considerable length that *connects* two transmission stations.

The ring bus arrangement shown in Figure 5 is acceptable when the development is connecting to a radial double circuit line.

Typical Connection Arrangements
for Generation Facilities Rated between 250MW and 500 MW

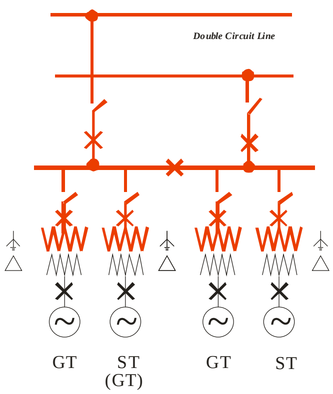


Figure 1 (Low Voltage Breakers are Optional)

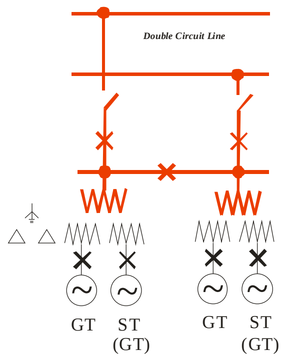


Figure 2

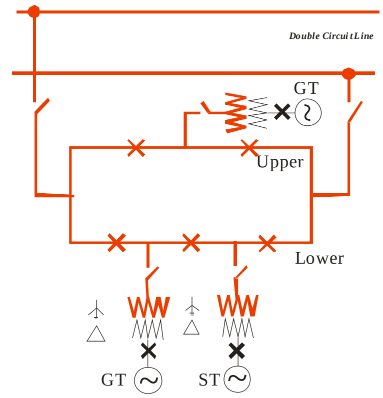


Figure 3

Typical Connection Arrangements
for Generation Facilities Rated Higher than 500 MW

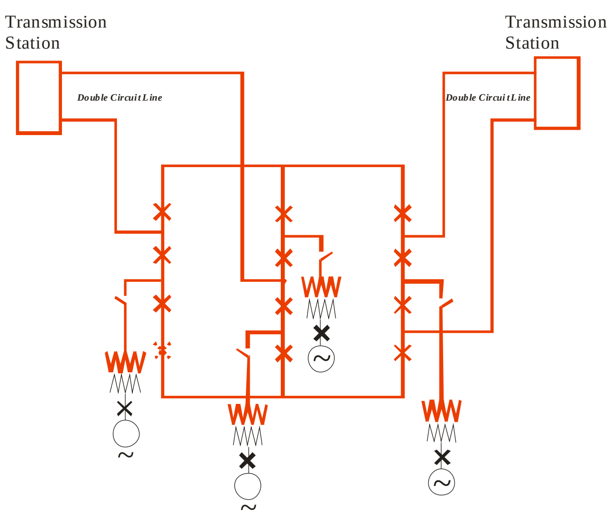


Figure 4

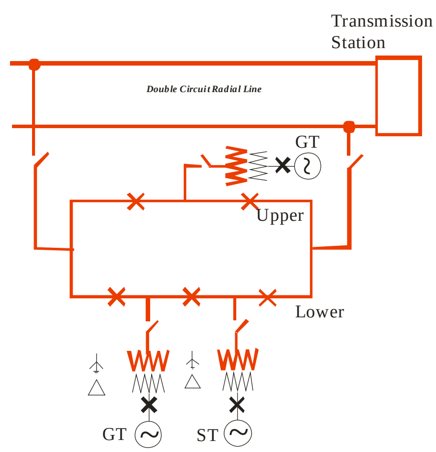


Figure 5

End of Section

References

Document ID	Document Name
NPCC A-01	Criteria for Review and Approval of Documents
NPCC A-02	Basic Criteria for Design and Operation of Interconnected Power Systems
NPCC A-04	Maintenance Criteria for Bulk Power System Protection
NPCC A-05	Bulk Power System Protection Criteria
NPCC A-11	Special Protection System Criteria
NPCC B-04	Guideline for NPCC AREA transmission Review
NPCC Criteria, Guides and Procedures can be found at http://www.npcc.org/document/abc.cfm	

– End of Document –

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 6

NextBridge-6

Reference: The IESO's June 29, 2018 Report at 1, lines 16-28.

INTERROGATORY

a) Does the IESO need to reject the entire 150 MWs of load every time the existing East-West Tie line is out of service? If not, explain in detail your response.

b) Explain in detail whether the rejection of the 150 MWs is related to or independent of the need to incur the capacity and energy replacement options and costs.

c) Does the rejection of 150 MWs of load occur any time the line is out of service, including planned and forced outages? If no, explain your response in detail.

d) Explain in detail whether the rejection of the 150 MWs of load is dependent on whether the load is near peak levels or is it at all times of the year at all load levels?

e) Confirm that the phrase "provided load can be restored within 8 hours" means that the existing East-West Tie line has been restored to service. If not confirmed, explain in detail how load has been restored without the existing East-West Tie line being brought back into service, including whether there are instances in which the East West Tie must be restored in order to bring back load.

f) Provide all documents, analysis, and studies that support that the existing East-West Tie line can in all types of outages, including a tower collapse, be restored within 8 hours.

   i. What actions would the IESO take if the existing East-West Tie line was out for an extended time (i.e., a week)?

   ii. Would sustained load curtailment be a potential outcome of extended outage of the existing East-West Tie line?

g) Confirm that the IESO would rather not be in the position of having to rely on the rejection of 150 MWs of load or any amount of load to maintain system reliability. If not confirmed, explain your response in detail.

h) How long has the SPS been used as an "interim measure" for the loss of the existing East-West Tie line?

i) In the past, has any load been rejected from the loss of the existing East-West Tie line?

j) What type of load is contemplated to be included in the SPS and rejected for the loss of the existing East-West tie?

k) In the past, what has been the outages and typical availability of the existing East-West line tie?

l) Confirm that the IESO would rather not be in the position of relying on an SPS. If not confirmed, explain your response in detail at 1, lines 26-28.

RESPONSE

a) No, the IESO would not need to reject 150 MW of load every time the existing East-West Tie line is out of service. Whether load rejection is armed (i.e. selected for rejection) for a given contingency, along with the amount that is armed, will vary based on the real-time operating conditions in the Northwest. The arming of load rejection is dependent on demand and generation levels, weather conditions, outage conditions, and import/export levels.

b) Load rejection would be used as an interim measure to reduce the amount of incremental capacity need in the Northwest before transmission reinforcements come into service. The capacity costs presented in the IESO's Addendum to the 2017 Updated Needs Assessment reflect only the incremental need above the 150 MWs of relief that may be addressed by load rejection.

c) No, please refer to the response to NextBridge Interrogatory 6a above. In addition, for planned outages, the outage would typically be scheduled for a time where conditions are favourable (e.g. low demand, high availability of generation, coordination with other scheduled outages, etc.).

d) Please see the response to NextBridge Interrogatory 6a) above.

e) Not confirmed; load can also be restored within 8 hours by bringing supply resources, such as Atikokan generating station, online. When planning the electricity system in the northwest, the IESO would only rely on load rejection as an interim measure if there are supply resources that are available in the Northwest which can be brought online within 8 hours. The IESO would not rely on load rejection as an interim measure if the only option to restore the load was to restore the East-West Tie line.

f) The IESO has not conducted such analysis or studies, and has no documents, supporting the fact that the existing East-West Tie line can, in all types of outages, be restored in 8 hours.

   i. If the existing East-West Tie line was out for an extended time, the IESO would take any action that is available to supply the load in the Northwest. These actions could include dispatching all local generation, cancelling or recalling planned outages, deploying voltage reductions and purchasing emergency energy.

   ii. If interim measures are deployed, a sustained load curtailment due to an extended outage of the East-West Tie line would be unlikely.

g) The IESO plans the system according to applicable planning standards and the IESO, as described in the IESO's Addendum to the 2017 Updated Needs Assessment, utilizes load rejection where permissible.

h) The original Northwest SPS came into service approximately 40 years ago and originally included functionality to arm load rejection for the loss of the East-West Tie. This functionality is now part of the Northwest SPS 2 which came into service in early 2017.

i) The Northwest SPS 2 has not been armed to reject load for the loss of the existing East-West Tie since it came into service. Before Northwest SPS 2 came into service, operating limits were, most recently, being calculated assuming the SPS was not being utilized. As such, the original Northwest SPS 1 had not been armed for the loss of the East-West Tie for quite some time (no records of it currently but it may have been armed historically when load levels in the Northwest were higher).

j) The Northwest SPS 2 currently has the functionality to arm load in the Thunder Bay area for the loss of the existing East-West Tie circuits.

k) Please refer to Hydro One's response to NextBridge Interrogatory 58(d), which addresses all lightning outages on the 230 kV system between Wawa and Marathon and Marathon and Lakehead stations. Please also refer to Hydro One's reponse to OEB Staff Interrogotories 4(b) and (c)(ii), which addresses all historical outages on the the 230 kV circuits between Wawa and Marathon.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 7

NextBridge-7

Reference: The IESO's June 29, 2018 Report at 2, lines 9 through 3, line 11.

INTERROGATORY

a) For each option identified, did the IESO conduct a probabilistic assessment of the likelihood that the option would be available to be used during 2021 and 2022? If so, please provide the assessment. If not, please provide your opinion on the likelihood each of the options will be available for use during 2021 and 2022.

b) Explain in detail whether the IESO would use one or a combination of the listed interim measures/options in 2021 and 2022.

RESPONSE

a) The IESO did not conduct a probabilistic assessment of the likelihood of each option being available during 2021 and 2022. It is the IESO's opinion that, within the range of costs outlined, the required incremental capacity could likely be acquired during 2021 and 2022.

b) The IESO's preference would be for the market to determine which of these listed interim measures (or other resources) would most cost effectively meet the incremental capacity need in 2021 and 2022. These examples were provided as they informed the range of costs the IESO presented for obtaining the required incremental capacity.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 8

NextBridge-8

Reference: The IESO's June 29, 2018 Report at 2, lines 9 through 3, line 11.

INTERROGATORY

Explain in detail why the IESO would or would not need to implement one or more of the identified options once the new East West Tie line is in-service.

RESPONSE

The identified options are to meet the incremental need for capacity in the Northwest due to a delay to the East-West Tie Expansion. Once the East-West Tie Expansion is in service, there would no longer be any incremental capacity need in the Northwest in the period outlined in the IESO's Addendum to the 2017 Updated Needs Assessment.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 9

NextBridge-9

Reference: The IESO's June 29, 2018 Report at 2 footnote 3

Preamble: IESO states that the 150-200 MW represented by the Manitoba import limit is not a real-time operating limit.

INTERROGATORY

a) Please provide a copy of the referred to planning criteria and reliability criteria.

b) Confirm that no real-time limit was provided for the Manitoba import because the IESO cannot reasonably rely on a higher limit than 200 MWs and still be in compliance with or be consistent with the referred to planning criteria and reliability criteria. If not confirmed, explain in detail your response.

c) Confirm that there are real-time limits on the Manitoba line that, at times, are lower than 150 MWs. If not confirmed, explain in detail your response.

RESPONSE

a) Ontario specific planning standards are described in the Ontario Resource and Transmission Assessment Criteria ("ORTAC") which is provided in the response to NextBridge Interrogatory 5, as Attachment 1, while reliability standards NERC TPL-001-4 and NPCC directory 1 are provided as Attachments 1 and 2 to this exhibit, respectively. How operating limits are derived and applied throughout the province is outlined in the Market Manual 7.4, provided as Attachment 3 hereto.

b) No real time limit was provided as the IESO Updated Needs Assessment Report and the IESO's Addendum to the 2017 Updated Needs Assessment are planning studies and only consider planning criteria.

c) If there are equipment outages in the Northwest or if there are high flows on the existing East-West Tie or Minnesota intertie, the Manitoba intertie operating limit can be lower than 150 MW.

Page Intentionally Blank

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    e. 3Ø internal breaker fault.
    f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
TPL-001-4	R1.	01/01/2015		
TPL-001-4	1.1.	01/01/2015		
TPL-001-4	1.1.1.	01/01/2015		
TPL-001-4	1.1.2.	01/01/2015		
TPL-001-4	1.1.3.	01/01/2015		
TPL-001-4	1.1.4.	01/01/2015		
TPL-001-4	1.1.5.	01/01/2015		
TPL-001-4	1.1.6.	01/01/2015		
TPL-001-4	R2.		01/01/2016	
TPL-001-4	2.1.		01/01/2016	
TPL-001-4	2.1.1.		01/01/2016	
TPL-001-4	2.1.2.		01/01/2016	
TPL-001-4	2.1.3.		01/01/2016	
TPL-001-4	2.1.4.		01/01/2016	
TPL-001-4	2.1.5.		01/01/2016	
TPL-001-4	2.2.		01/01/2016	
TPL-001-4	2.2.1.		01/01/2016	
TPL-001-4	2.3.		01/01/2016	
TPL-001-4	2.4.		01/01/2016	
TPL-001-4	2.4.1.		01/01/2016	
TPL-001-4	2.4.2.		01/01/2016	
TPL-001-4	2.4.3.		01/01/2016	
TPL-001-4	2.5.		01/01/2016	
TPL-001-4	2.6.		01/01/2016	
TPL-001-4	2.6.1.		01/01/2016	
TPL-001-4	2.6.2.		01/01/2016	
TPL-001-4	2.7.		01/01/2016	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

<u>United States</u>

TPL-001-4	2.7.1		01/01/2016	
TPL-001-4	2.7.2.		01/01/2016	
TPL-001-4	2.7.3.		01/01/2016	
TPL-001-4	2.7.4.		01/01/2016	
TPL-001-4	2.8		01/01/2016	
TPL-001-4	2.8.1.		01/01/2016	
TPL-001-4	2.8.2.		01/01/2016	
TPL-001-4	R3.		01/01/2016	
TPL-001-4	3.1.		01/01/2016	
TPL-001-4	3.2.		01/01/2016	
TPL-001-4	3.3.		01/01/2016	
TPL-001-4	3.3.1.		01/01/2016	
TPL-001-4	3.3.1.1.		01/01/2016	
TPL-001-4	3.3.1.2.		01/01/2016	
TPL-001-4	3.3.2.		01/01/2016	
TPL-001-4	3.4.		01/01/2016	
TPL-001-4	3.4.1.		01/01/2016	
TPL-001-4	3.5.		01/01/2016	
TPL-001-4	R4.		01/01/2016	
TPL-001-4	4.1.		01/01/2016	
TPL-001-4	4.1.1.		01/01/2016	
TPL-001-4	4.1.2.		01/01/2016	
TPL-001-4	4.1.3.		01/01/2016	
TPL-001-4	4.2.		01/01/2016	
TPL-001-4	4.3.		01/01/2016	
TPL-001-4	4.3.1.		01/01/2016	
TPL-001-4	4.3.1.1.		01/01/2016	
TPL-001-4	4.3.1.2.		01/01/2016	
TPL-001-4	4.3.1.3.		01/01/2016	
TPL-001-4	4.3.2.		01/01/2016	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

United States

TPL-001-4	4.4.		01/01/2016	
TPL-001-4	4.4.1.		01/01/2016	
TPL-001-4	4.5.		01/01/2016	
TPL-001-4	R5.		01/01/2016	
TPL-001-4	R6.		01/01/2016	
TPL-001-4	R7.	01/01/2015		
TPL-001-4	R8.		01/01/2016	
TPL-001-4	8.1.		01/01/2016	

Page Intentionally Blank

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
December 01, 2009
September 30, 2015

Adopted by the Members of the Northeast Power Coordinating Council, Inc., on December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/1/2009		New
1	4/20/2012	Errata Changes in Appendices B and E.	Errata
2	9/30/2015	TFCP/TFCO Review	Revised

Table of Contents

1.0 Introduction

1.1 Title: Design and Operation of the Bulk Power System

1.2 Directory Number: 1

1.3 Objective:

The objective of this Directory is to provide a "design-based approach" to design and operate the **bulk power system** to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from any of the contingencies referenced in **Requirement R7** and **Requirement R13.** The intent of this approach is to avoid instability, voltage collapse and widespread cascading outages. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining **bulk power system**.

In NPCC the technique for achieving this level of reliability is to require that the **bulk power system** be designed and operated to meet the performance requirements for the representative **contingencies** as specified in this Directory. Simulations shall be used to assess and analyze these **contingencies.** As a minimum**, contingency** events shall be applied on **bulk power system** elements and the resulting performance requirements shall be monitored on the **bulk power system.** If an entity becomes aware[1] of a **contingency** not on a **bulk power system** element that results in a **significant adverse impact** outside the **local area,** that entity must design and/or operate the system to respect that event.

The characteristics of a reliable **bulk power system** include adequate **resources** and transmission to reliably meet projected customer electricity **demand** and energy requirements as prescribed in this document.

1.4 Effective Date: December 1, 2009

1.5 Background

This Directory was developed from the NPCC A-2 criteria document - *Basic Criteria for the Design and Operation of Interconnected Power Systems* (May 6, 2004 version). Guidelines and Procedures for consideration in the implementation of this Directory are provided in the Appendices.

[1] NPCC Members shall strive to meet the reliability objectives in this document. However, there is no affirmative requirement for an NPCC Member to explicitly identify every potential non-BPS contingency that may impact the BPS.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Planning Coordinators
Transmission Planners
Resource Planners
Generator Owners
Transmission Owners

1.6.2 Applicability of NPCC Criteria:

The requirements of an NPCC Directory apply only to those facilities defined as NPCC **bulk power system** elements as identified through the performance based methodology of NPCC Document A-10, *"Classification of Bulk Power System Elements*," the list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in external tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements. NPCC will not enforce compliance to the NPCC Directory requirements in this document on any entity that is not an NPCC Full Member.

2.0 Defined Terms:

Unless specifically noted in this document terms in bold typeface are defined in the NPCC Glossary of Terms.

3.0 NPCC Full Member Criteria:

Information for Planning and Operational Assessments

R1 Each Functional Entity that owns equipment shall submit verified information representing the physical or control characteristics of its equipment for system modelling and reliability analysis of the **bulk power system** in accordance with **Requirement R2**.

R2 Each Planning Coordinator and Reliability Coordinator shall collect and maintain information needed for system modelling and reliability analysis of the **bulk power system.**

R2.1 System modelling information shall be submitted to an NPCC Task Force upon request.

R3 Each Reliability Coordinator shall share and coordinate forecast system information and real-time information to enable and enhance the analysis and modeling of the interconnected **bulk power system** by security application software on energy management systems.

Resource Adequacy

R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate **resource** adequacy of its Planning Coordinator **Area** portion of the **bulk power system** to demonstrate that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to **resource** deficiencies is, on average, no more than 0.1 days per year.

R4.1 Make due allowances for **demand** uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator **Areas**, transmission transfer capabilities, and **capacity** and/or **load** relief from available operating procedures.

R5 Each Planning Coordinator shall report and obtain Reliability Coordinating Committee (RCC) approval for its Review of **Resource** Adequacy. Appendix D provides guidance for the Area Review of **Resource** Adequacy.

R5.1 The Review of **Resource** Adequacy will be presented to the NPCC Task Force on Coordination of Planning (TFCP). Comprehensive and Interim reviews shall be presented to the TFCP before the beginning of the first time period covered by the assessment.

R5.2 A Comprehensive Review of **Resource** Adequacy is required every three years and will cover a time period of five years. If changes in planned facilities or forecasted system conditions warrant, TFCP may require a Comprehensive Review of **Resource** Adequacy in less than 3 years.

R5.3 In subsequent years, each Planning Coordinator shall conduct an Annual Interim Review of **Resource** Adequacy that will cover, at a minimum, the remaining years studied in the Comprehensive Review of **Resource** Adequacy.

R6 Each Reliability Coordinator shall coordinate outages and deratings of **resources** to verify adequate **resources** will be available to meet the forecasted **demand** and **reserve** requirements. Appendix F provides guidance for Operational Planning Coordination.

R6.1 A Summer and Winter Reliability Assessment will be presented to the NPCC Task Force on Coordination of Operation (TFCO) every year.

Transmission Planning

R7 Each Transmission Planner and Planning Coordinator shall plan its **bulk power system** to have sufficient transmission capability to meet the respective requirements as specified in Table 1 while serving forecasted **demand**.

R7.1 Credible combinations of system conditions which stress the system shall be modelled including, **load** forecast, inter-**Area** and intra-**Area** transfers, transmission configuration, active and reactive **resources**, **generation** availability and other dispatch scenarios. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

R8 Each Transmission Planner and Planning Coordinator shall assess the impact of the extreme **contingencies** listed in Table 2. Appendix C provides guidance for testing and analyzing extreme **contingencies**.

R9 Each Transmission Planner and Planning Coordinator shall assess the impact of extreme system conditions, one condition at a time, subject to **contingencies** as listed in the “Extreme System Conditions” category of Table 2.

R10 Each Transmission Planner and Planning Coordinator shall have procedures and implement a system design that ensures equipment capabilities are adequate for **fault** current levels with all transmission and **generation** facilities in service for all operating conditions which are not prohibited by a procedure and coordinate these procedures with materially affected Transmission Planner and Planning Coordinator Areas.

R11 Each Planning Coordinator shall conduct and obtain Reliability Coordinating Committee (RCC) approval for its Transmission Review. Appendix B provides guidance for Transmission Reviews.

R11.1 A Comprehensive Transmission Review is required at least once every five years or if major or pervasive system changes have occurred. If changes in the planned facilities or forecasted system conditions warrant, the Task Force on System Studies (TFSS) may require a Comprehensive Transmission Review in less than five years.

R11.2 The proposal for the type of annual Transmission Review shall be presented to TFSS by March of the year during which the review is conducted. Approval for the type of Transmission Review shall be obtained from the TFSS. The annual Transmission Review shall be presented to the TFSS by April of the following year.

R11.3 If the results of the Transmission Review indicate that the planned **bulk power system** will not be in conformance with NPCC Directory #1, the Transmission Review shall incorporate a corrective action plan to achieve conformance.

Special Protection Systems

R12 Each Functional Entity that proposes a new or modified **SPS** shall consider the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

R12.1 Provide a rationale and justification to the TFCP including factors such as project delays, temporary construction configurations, unusual combinations of system conditions, equipment outages and infrequent **contingencies**.

Transmission Operation

R13 Each Reliability Coordinator and Transmission Operator shall establish **normal transfer capabilities** and **emergency transfer capabilities, for** its portion of the **bulk power system** to meet the respective performance requirements for the **contingencies** as specified in Table 3.

R14 Each Reliability Coordinator and **Transmission** Operator shall operate to **normal transfer capabilities** unless an **emergency,** in accordance with NPCC Directory# 2, is identified.

R15 Each Reliability Coordinator and Transmission Operator shall make system adjustments once an **emergency** has been identified, including the pre-**contingency** disconnection of **firm load,** to avoid exceeding **emergency transfer capabilities.**

R16 Each Reliability Coordinator and Transmission Operator shall assess the status of the **bulk power system** immediately after the occurrence of any **contingency** and prepare for the next **contingency** as specified in Table 3.

R16.1 Voltage reduction and shedding of **firm load** shall be deployed to return the system to a secure state, if other system adjustments are not adequate. Voltage reduction need not be initiated and **firm load** need not be shed to observe a post contingency loading requirement until the **contingency** occurs, provided that adequate response time for this action is available.

R16.2 System adjustments shall be completed as quickly as possible following any **contingency,** but within 30 minutes after the occurrence of any **contingency** specified in Table 3.

R17 Each Reliability Coordinator shall notify the applicable Reliability Coordinators of forced outages of any facility as per the NPCC Transmission Facilities Notification List and of any other condition which may impact inter-**Area** reliability.

R18 Each Reliability Coordinator shall coordinate scheduled outages of facilities that are on the NPCC Transmission Facilities Notification List sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Appendix F provides guidance for Operational Planning Coordination.

R18.1 Review and update its Facilities Notification List and submit the list to the NPCC Task Force on Coordination of Operation (TFCO) annually.

R19 Each Reliability Coordinator shall coordinate voltage control between Transmission Operator Areas. Appendix G provides guidance for Inter- Reliability Coordinator **Area** Voltage Control.

R19.1 Metering for **reactive power resources** and voltage controller status shall be consistent between adjacent Transmission Operators.

R19.2 Upon request from the TFCO, perform an Inter-**Area** Voltage Control Assessment.

4.0 Compliance:

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

NPCC will not enforce a duplicate sanction for the violation of any Directory#1 requirement that is also required for compliance with a NERC Reliability Standard.

Prepared by: Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or other portions of the document such as links, etc., only require RCC approval.
Errata may be corrected by the Lead Task Force at any time.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:
NPCC Glossary of Terms
Emergency Operations (NPCC Directory #2)
Bulk Power System Protection Criteria (NPCC Directory #4)
Reserve (NPCC Directory #5)
Special Protection Systems (NPCC Directory #7))
Classification of Bulk Power System Elements (A-10)

Table 1

Planning Design Criteria: Contingency events, Fault type and Performance requirements to be applied to bulk power system elements

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
I **Single Event**	1. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three-phase **fault** with **normal fault clearing**	i. to viii
	2. Opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**	
	3. Loss of single pole of a direct current facility	No **fault**	
	4. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers	
	5. **Fault** on a circuit breaker	Phase to ground **fault,** with **normal fault clearing**	
	6. Simultaneous **fault** on two adjacent transmission circuits on a multiple circuit tower.	Phase to ground **faults** on different phases of each circuit, with **normal fault clearing**	
	7. Simultaneous permanent loss of both poles of a direct current bipolar facility	Without an ac **fault**	

NPCC Directory #1
Table 1

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
	8. The failure of a circuit breaker to operate when initiated by a **SPS** after a **fault** on the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault**, with **normal fault clearing**	i. to viii
	9. The failure of a circuit breaker to operate when initiated by a **SPS** after opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**	

Category	**Contingency** events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements
II Event(s) after a first loss and after System Adjustment	1. Following the loss of any critical: a. transmission circuit, b. transformer, c. series or shunt compensating device or d. generator e. Single pole of a direct current facility and after System Adjustment, Category I **Contingencies** shall also apply.	Any Category I event as described above.	Performance requirements i to viii apply **Area generation** and **power** flows are adjusted between outages by the use of **resources** available within ten minutes following notification and other system adjustments such as HVDC and phase angle regulator adjustments that can be made within 30 minutes.

Performance Requirements for the contingencies defined in Table 1:

i. Loss of a major portion of the system or unintentional separation of a major portion of the system shall not occur.

ii. Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining **bulk power system**.

iii. Voltages and loadings shall be within applicable limits for pre-**contingency** conditions.

iv. Voltages and loadings shall be within **applicable limits** for post-**contingency** conditions except for small or radial portions of the system as described in ii.

v. The **stability** of the **bulk power system** shall be maintained during and following the most severe **contingencies**, with due regard to successful and unsuccessful **reclosing** except for small or radial portions of the system as described in ii.

vi. For each of the **contingencies** that involve **fault** clearing, **stability** shall be maintained when the simulation is based on **fault** clearing initiated by the **"system A" protection group** and also shall be maintained when the simulation is based on **fault** clearing initiated by the **"system B" protection group**. When applying this requirement to **contingency** event *#6*, the failure of a **protection group** shall apply only to one circuit at a time. When evaluating **contingency** event#4 breaker failure protection is assumed to operate correctly even if only a single breaker failure **protection system** exists.

vii. Regarding **contingency** event*#6* if multiple circuit towers are used only for station entrance and exit purposes and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion. (See Appendix E.)

viii. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner except for small or radial portions of the system as described in ii.

Table 2

Planning Criteria: Extreme Contingency and System Conditions, Fault type and Performance Assessments to be applied to bulk power system elements

.

Category	**Contingency** events Simulate the removal of all elements that **protection systems**, including **Special Protection Systems,** are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) and/or condition applied On the listed **elements** where applicable	Performance to be assessed
Extreme Contingency	1. Loss of the entire capability of a generating station.	No **Fault**	i, ii, iii
	2. Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.	No **Fault**	
	3. Loss of all transmission circuits on a common right-of-way.	No **Fault**	
	4. **Fault** on of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three- phase **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers. **(**with due regard to successful and unsuccessful reclosing.)	
	5. **Fault** on a circuit breaker	Three-phase **fault**, with **normal fault clearing**	
	6. Sudden loss of a large **load** or major **load** center.	No **Fault**	
	7. The effect of severe power swings arising from disturbances outside the NPCC's interconnected systems.	**Fault** applied as necessary.	
	8. Failure of a **Special Protection System**, to operate when required following the normal contingencies listed in Table 1, Category I, Single Event.	As listed in Table 1, Category I, Single Event.	
	9. The operation or partial operation of a **Special Protection System** for an event or condition for which it was not intended to operate.	No **Fault**	
	10. Sudden loss of fuel delivery system to multiple plants, (e.g. gas pipeline contingencies).	No **Fault.**	
	Any additional extreme **contingencies** identified by each Planning Coordinator Area.	**Fault** applied as necessary.	

NPCC Directory #1
Table 2

Category	**Contingency** events Simulate the removal of all elements that **protection systems**, including **Special Protection Systems,** are expected to automatically disconnect for each event that involves an AC **fault.**	**Fault** type (permanent) and/or condition applied On the listed **elements** where applicable	Performance to be assessed
Extreme System Conditions	Contingency events listed in Table 1, Category I, Single Event	Peak **load** conditions resulting from extreme weather.	i (b, c), ii, iii
		Generating unit(s) fuel shortage (e.g. gas supply adequacy or low hydro) under normal weather peak conditions	i (c), ii, iii

Performance Assessment

i. Model the following pre-**contingency** conditions:

   a. transfers within or between Transmission Planner and Planning Coordinator Areas should be studied at values not expected to be exceeded more than 25% of the time.

   b. highly probable dispatch patterns of **generation** for the transfers being studied

   c. appropriate **load** representation (e.g. active and reactive power as a function of voltage) for transient tests and post transient **load** flows.

ii. Examine post **contingency** steady state conditions, as well as stability, overload, cascading outages and voltage collapse to obtain an indication of system robustness and determine the extent of any widespread system disturbance

iii. Where assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies shall be conducted.

Table 3

Operating Criteria: Contingency events, Fault type and Performance requirements to be applied to bulk power system elements to establish transfer capabilities.

	Contingency events Simulate the removal of all **elements** that **protection systems**, including **Special Protection Systems**, are expected to automatically disconnect for each event that involves an AC fault.	**Fault** type (permanent) On the listed **elements** where applicable	Performance requirements **Normal Transfer Capability**	Performance requirements **Emergency Transfer Capability** (only after an **Emergency** is identified)
	1. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Three-phase **fault**, with **normal fault clearing**	i, ii, iii, iv, v, vi, vii, ix, x	i, ii, iii, iv, v, vi, vii, ix, xi
	2. Opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault**		
	3. Loss of single pole of a direct current facility	No **fault**		
	4. **Fault** on any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault** with failure of a circuit breaker to operate and correct operation of a breaker failure **protection system** and its associated breakers.	i,ii,iii,iv,v,vi,vii, viii, ix,x	**Contingency** Events 4 through 8 do not apply after an emergency is identified.
	5. **Fault** on a circuit breaker	Phase to ground **fault,** with **normal fault clearing**		
	6. Simultaneous **fault** on two adjacent transmission circuits on a multiple circuit tower.	Phase to ground **faults** on different phases of each circuit with **normal fault clearing**		
	7. Simultaneous permanent loss of both poles of a direct current bipolar facility	Without an ac **fault**		

NPCC Directory #1
Table 3

	8. The failure of a circuit breaker to operate when initiated by a **SPS** after a **fault** on the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	Phase to ground **fault**, with **normal fault clearing**	i,ii,iii,iv,v,vi,vii, viii, ix,x	**Contingency** Events 4 through 8 do not apply after an emergency is identified.
	9. The failure of a circuit breaker to operate when initiated by a **SPS** after an opening of any circuit breaker or the loss of any of the following: a. transmission circuit b. transformer c. shunt device d. generator e. bus section	No **fault.**		

Performance Requirements for the contingencies defined in Table 3:

i. Loss of a major portion of the system or unintentional separation of a major portion of the system shall not occur.

ii. Loss of small or radial portions of the system is acceptable provided the performance requirements are not violated for the remaining **bulk power system.**

iii. Individual Reliability Coordinator Areas shall be operated in a manner such that **Contingencies** and conditions applied can be withstood without causing **significant adverse impact** on other Reliability Coordinator Areas.

iv. Voltages and loadings shall be within applicable limits for the pre-**contingency** conditions.

v. Voltages and loadings shall be within **applicable limits** for post-**contingency** conditions except for small or radial portions of the system as described in ii.

vi. The **stability** of the **bulk power system** shall be maintained, with due regard to successful and unsuccessful **reclosing** except for small or radial portions of the system as described in ii.

vii. For each of the **contingencies** that involve **fault** clearing, **stability** shall be maintained when the simulation is based on **fault** clearing initiated by the **"system A" protection group**, and also shall be maintained when the simulation is based on **fault** clearing initiated by the **"system B" protection group**. When applying this requirement to **contingency** event#*6* the failure of a **protection group** shall apply only to one circuit at a time. When evaluating **contingency** event#4 breaker failure protection is assumed to operate correctly even if only a single breaker failure **protection system** exists

viii. Regarding **contingency** event#6 if multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion. (See Appendix E.)

ix. Appropriate adjustments shall be made to Reliability Coordinator Area operation to accommodate the impact of **protection group outages**, including the **outage** of a **protection group** which is a part of a Type I **special protection system**. For typical periods of forced outage or maintenance of a **protection group**, it can be assumed, unless there are indications to the contrary, that the remaining **protection** will function as designed. If the **protection group** will be out of service for an extended period of time, additional adjustments to operations may be appropriate considering other system conditions and the consequences of possible failure of the remaining **protection group.**

x. Normal transfer levels shall not require system adjustments before attempting manual reclosing of elements unless specific instructions describing alternate actions are in effect to maintain stability of the **bulk power system.**

xi. Emergency transfer levels may require system adjustments before attempting manual reclosing of elements to maintain stability of the **bulk power system**.

Operating to the **contingencies** listed above in Table 3 is considered to provide an acceptable level of **bulk power system** security. However, under high risk conditions, such as severe weather, the expectation of the occurrence of contingencies not listed in Table 3 and/or the associated consequences may be judged to be significantly greater. When these conditions exist, consideration should be given to operating in a more conservative manner.

Appendix A - NERC ERO Reliability Standard Requirements:

The NERC ERO Reliability Standards containing requirements associated with this Directory but not necessarily enforceable in all NPCC areas include but may not be limited to:

3.1 EOP-001-2.1b - Emergency Operations Planning
3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
3.3 IRO-002-2 - Reliability Coordination - Facilities
3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
3.5 MOD-010-0 - Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
FERC approved the withdrawal of MOD-011-0 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-011-0 was replaced by MOD-032-1--- Standard subject to future enforcement.
3.7 MOD-012-0 — Dynamics Data for Modeling and Simulation of the Interconnected Transmission System
3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
FERC approved the withdrawal of MOD-013-1 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-013-1 was replaced by MOD-032-1--- Standard subject to future enforcement.
3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
FERC approved the withdrawal of MOD-014-0 pursuant to a letter order issued May 1, 2014 in Docket No. RD14-5-000. MOD-014-0 was replaced by MOD-032-1--- Standard subject to future enforcement.
3.10 MOD-016-1.1 — Actual and Forecast Demands , Net Energy for Load, Controllable DSM
3.11 TOP-001-1a — Reliability Responsibilities and Authorities
3.12 TOP-002-2.1b— Normal Operations Planning
3.13 TOP-003-1 — Planned Outage Coordination
3.14 TOP-004-2 — Transmission Operations
3.15 TPL-001-0.1 — System Performance Under Normal (No Contingency) Conditions (Category A) Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-001.01 is 12/31/2015. Please see the details link for TPL-001-4 for more information.
3.16 TPL-001-4 — Transmission System Planning Performance Requirements
3.17 TPL-002-0b — System Performance Following Loss of a Single Bulk Electric System Element (Category B)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-002.0b is 12/31/2015. Please see the details link for TPL-001-4 for more information.
3.18 TPL-003-0b — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-003.0b is 12/31/2015. Please see the details link for TPL-001-4 for more information.
3.19 TPL-004-0a — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
Will be replaced by TPL-001-4 (R2 through R6 and R8). The inactive date for TPL-004.0a is 12/31/2015. Please see the details link for TPL-001-4 for more information.
3.20 VAR-001-4 — Voltage and Reactive Control

Appendix B - Guidelines and Procedures for NPCC Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **BPS reliability**. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the **reliability** of the planned **bulk power system** of each Planning Coordinator Area of NPCC. The purpose of these reviews is to determine whether each Planning Coordinator Area's planned bulk power transmission system is in conformance with the NPCC Directory #1 *Design and Operation of the Bulk Power System*. The annual Area Transmission Review required in **Requirement R11** is presented for this purpose. It is expected that this Review will cover Directory #1 requirements as they apply to the **bulk power system**.

2.0 Purpose of Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinator's planned **bulk power system** based on its projection of available **demand**, transmission, and **resources**, is in conformance with the Directory #1 criteria. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the **reliability** of the NPCC Interconnected Systems will be maintained.

3.0 Study Year To Be Considered

It is suggested that a study year of 4 to 6 years from the reporting date is a realistic one, both from the viewpoint of minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond 6 years to address identified marginal conditions that may have longer lead-time solutions.

4.0 Types and Frequency of Reviews

As described in **Requirement R11,** each Planning Coordinator is required to present an annual transmission review to TFSS. However, the review presented by the Planning Coordinator may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

A Comprehensive Review is a thorough assessment of the Planning Coordinator's entire **bulk power system**, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in **Requirement R11.**

In the years between Comprehensive Reviews, Planning Coordinators may conduct either an Interim Review, or an Intermediate Review, depending on the extent of the Planning Coordinator's system changes since its last Comprehensive Review. If the system changes are relatively minor, the Planning Coordinator may conduct an Interim Review. In an Interim Review, the Planning Coordinator provides a summary of the changes in planned facilities and forecasted system conditions since its last Comprehensive Review and a brief discussion and assessment of the impact of those changes on the bulk power transmission system. No new analyses are required for an Interim Review.

If the Planning Coordinator's system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Planning Coordinator's system, the Planning Coordinator may conduct an Intermediate Review. An Intermediate Review covers all the elements of a Comprehensive Review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes.

In March of each year, after a Planning Coordinator presents a proposal for the type of review to be conducted during the current year, TFSS will consider each Planning Coordinator's proposal. TFSS will either indicate their concurrence, or require the Planning Coordinator to conduct a more extensive review if the Task Force feels that such is warranted based on the Planning Coordinator's system changes since its last Comprehensive Review.

5.0 Format of Presentation – Comprehensive and Intermediate Review

a) Introduction

- Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.
- Describe the type and scope of this review.
- For a Comprehensive Review, describe the existing and planned **bulk power system** facilities included in this review.
- Describe changes in system facilities, **bulk power system elements** and **loads** since the most recent Comprehensive Review.
- Include maps and one-line diagrams of the system showing proposed changes as necessary.
- Describe the **demand** levels to be studied, according to the range of forecast system **demands.**
- Identify projected firm transfers and interchange schedules.

b) Present the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of “critical” **contingencies**.

c) Steady State Assessment

- Present the **load** model, power factor, **demand** side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why **contingencies** not simulated would produce less severe results.

- Provide information on the **generation** dispatch conditions assumed in the analysis.

- Include plots of "base case" **load** flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.

- Present the effects of major planned changes on the system.

- Identify applicable transfer limits within and between Planning Coordinator Areas.

- Show the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.

d) Stability Assessment

Present and/or refer to significant studies showing the effect of **contingencies** on the system and report on the most severe **contingencies** in the following manner:

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why **contingencies** not simulated would produce less severe results.

- The nature of the **fault** applied, **elements** switched, and **fault clearing** times.

- Plots of angles versus time for significant machines, response of real and reactive power control devices, voltages at significant buses and significant interface flows.

For a Comprehensive or Intermediate Review, present the **load** model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

e) **Fault** Current Assessment

- Present the methodology and assumptions used in the **fault** current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Present instances where **fault** levels exceed equipment capabilities and measures to mitigate such occurrences.

- Present changes to **fault** levels at stations adjacent to other Planning Coordinator Areas.

f) Extreme **Contingency** Assessment

- Present the scope of the analyses including a description of the system conditions assessed. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

- Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining **contingencies** not simulated would produce less severe results.

- Review the results for widespread cascading due to overloads, instability or voltage collapse caused by extreme **contingencies**

- In the case where **contingency** assessment reveals serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

g) Extreme System Condition Assessment

- Present the scope of the analyses including a description of the system conditions assessed. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of "critical" **contingencies**.

- Provide the rationale for the loss of fuel supply conditions selected for evaluation and an explanation of why other loss of fuel supply conditions not simulated would produce less severe results.

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining **contingencies** not simulated would produce less severe results.

- In the case where extreme condition assessment reveals serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

h) Review of **Special Protection Systems (SPSs)**

- Present the scope of review. A Comprehensive Review should review all the existing, new and modified **SPSs** included in its transmission plan. An Intermediate Review may focus on the new and modified **SPSs**, and just those existing **SPSs** that may have been impacted by system changes since they were last reviewed.

- Present the need and utilization for Type I and Type II **SPSs.** For instances where a **SPS** utilization is anticipated to increase, the TFSS should inform the Task Force on Coordination of Planning (TFCP) of this finding.

- Review the validity of the classification of Type III **SPSs**. For instances where a **SPS** which was formerly considered to have only local consequences is identified as having the potential for inter- Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Force on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the **SPS** should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System **Special Protection Systems** (SPS)* in Directory #7.

i) Review of Dynamic Control Systems (DCSs)

Review of potential consequences of failure or misoperation of Dynamic Control Systems (DCS), as defined in NPCC Document C-33 *Procedure for Analysis and Classification of Dynamic Control Systems*. For Type I and Type II DCSs, present and/or refer to appropriate **stability** studies analyzing the consequences of failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactful existing and new DCSs, but an Intermediate Review may focus on new DCSs and only those existing DCSs that may have been impacted by system changes since they were last reviewed.

j) Review of Exclusions to the Directory#1 *Criteria*

Review any exclusions granted under NPCC *Guidelines for Requesting Exclusions to Simultaneous Loss of Two Adjacent Transmission Circuits on a Multiple Circuit Tower* (Appendix E). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus on just those exclusions that may have been impacted by system changes since they were last reviewed.

k) Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

a) Introduction of Interim Review

b) Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

c) Changes in Facilities (Existing and Planned) and Forecasted System Conditions Since the Last Comprehensive Review.

- **Load** Forecast
- **Generation Resources**
- **Bulk Power System elements**
- Transmission Facilities
- **Special Protection Systems**
- Dynamic Control Systems
- Exclusions

d) Brief Impact Assessment and Overview Summary

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**, based on engineering judgment and internal and joint system studies as appropriate.

7.0 Documentation

The documentation required for a Comprehensive or Intermediate Review should be in the form of a report addressing each of the items of the above presentation format. The report should be accompanied by the Planning Coordinator's **bulk power system** map and one-line diagram, summary tables, figures, and appendices, as appropriate. The report may include references to other studies performed by the Planning Coordinator or by utilities within the Planning Coordinator Area that are relevant to the Area Transmission Review, with appropriate excerpts from those studies.

The documentation required for an Interim Review should be in the form of a short summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Transmission Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and consider whether to accept the report as complete and in full conformance with these Guidelines :

a. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.

b. If there is no concurrence about the results and conclusion(s) of the Planning Coordinator's Review, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS will prepare a summary of the results of its review, and present the summary to the TFCP.

c. If the report is considered as complete and in full conformance with these Guidelines, TFSS will accept the report.

8.2 If the Area Transmission Review indicates an overall **bulk power system** reliability concern (not specific to the Planning Coordinator's planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning

8.3 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning. The TFCP will then review and vote on the completeness and acceptability of the Area Transmission Review and report its finding to the Reliability Coordinating Committee for a final review and approval.

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

Extreme **Contingencies** (ECs) are tested "as a measure of system strength" in order to identify potential patterns of weakness in the bulk power transmission system. This procedure for the testing and analysis of ECs should be used when testing ECs for NPCC studies or studies submitted for NPCC review.

This procedure applies to transmission planning studies that consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. It principally applies to NPCC - wide studies of the **bulk power system** and generally does not apply to studies normally conducted by NPCC Transmission Planner and Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure also applies to Area Transmission Reviews, and may be applicable to other studies conducted by the Transmission Planner and Planning Coordinators, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. Certain Transmission Planners or Planning Coordinators may elect to completely mitigate the effects of specific ECs.

Finally, this procedure should be followed in multi-regional studies in which NPCC is an active participant, to the extent that this is within the scope of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined as per **Requirement R8.** Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to **contingencies** which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, **contingencies** which would result in reversal of major power transfers, e.g. loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings. In considering specific **contingencies** to be investigated in an NPCC study, all relevant testing done at the Transmission Planner and Planning Coordinator level should first be reviewed.

In general, a **contingency** in a particular Planning Coordinator Area should be studied, if requested by any other Transmission Planner or Planning Coordinator, based on a reasonable surmise that the requesting Entity may be adversely affected.

3.0 Modeling Assumptions

As referenced in Table 2, performance assessment "i" for **Requirement R8**, the assumed **generation** dispatch, transfers levels, **load** levels and **load** representation are major considerations in EC tests. It is not the intent to test the worst imaginable extreme, but EC tests should be severe.

The specification of appropriate **load** representation applies to long term stability tests or post-transient power flows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

A question in evaluating the results of a particular test run is - "Does the system "pass" or "fail" for this **contingency**?" While in the final analysis this is a matter of informed engineering judgment, factors which should be considered include:

1. Lines or transformers loaded above **short time emergency ratings**,

2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),

3. Magnitude and geographic distribution of such overloads and voltage violations across the system,

4. Transient generator angles, frequencies, voltages and power,

5. Operation of Dynamic Control Systems and **Special Protection Systems** (**SPS**),

6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,

7. Net loss of source resulting from any combination of loss of synchronism of one or more units, **generation** rejection or runback initiated by SPS, or any other defined system separation,

8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one Planning Coordinator Area, should be a major consideration),

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,

10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

Finally, a judgment should be attempted as to whether a "failure" is symptomatic of a basic system weakness, or just sensitivity to a particular EC. For example, should failures turn up for several EC tests in a particular part of the system, it is likely that a basic system weakness has been identified.

The loss of portions of the system should not necessarily be considered a failed result, provided that these losses do not jeopardize the integrity of the overall **bulk power system.**

NPCC study groups should avoid characterizations like "successful" and "unsuccessful" when commenting on individual runs. Rather, the specific initial conditions directly causing or related to the failure, the complete description of the nature of the failure (e.g., voltage collapse, instability, system separation, as well as the facilities involved), and the extent of potential impact on other Planning Coordinator Areas should be reported.

5.0 Evaluating the Results of EC Tests

EC test reports should focus on those portions of the system in which basic system weaknesses may be developing, rather than on the results of one specific **contingency**.

Any patterns of weaknesses should be identified, which may include reference to earlier NPCC studies and/or Transmission Planner, Planning Coordinator or member system investigations. There is also a need to distinguish between a "failed" test which indicates sensitivity only to a particular **contingency** run and a "failed" test which indicates a more general system weakness (always keeping in mind the severity of possible consequences of the **contingency**). Actions taken by member systems, Transmission Planners or Planning Coordinators to reduce the probability of occurrence or mitigate the consequences of the **contingency** should also be cited.

NPCC follow-up, after publication of a final report, is appropriate only for instances of possible general system weakness. In these instances, the results should be specifically referred to the affected Transmission Planner(s) or Planning Coordinator(s) for further and more detailed investigation with subsequent reporting to NPCC.

Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by the NPCC and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, each Planning Coordinator submits to the Task Force on Coordination of Planning its Area Review of **Resource** Adequacy, which is an annual assessment to demonstrate that the proposed **resources** of each NPCC Planning Coordinator will meet NPCC **resource** adequacy planning requirements, consistent with these guidelines. The Task Force is charged, on an ongoing basis, with reviewing and recommending NPCC Reliability Coordinating Committee approval of these reviews of **resource** adequacy of each Planning Coordinator Area of NPCC.

The NPCC role in monitoring conformance with the NPCC Directory #1 - *Design and Operation of Bulk Power System* is essential because under this criterion, each Planning Coordinator determines its **resource** requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate **resources** will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate **resources** in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.

It is recognized that all Planning Coordinators may not necessarily express their own **resource** adequacy criterion as stated in **Requirements R4**, **Requirement R5** and **Requirement R6** of the Directory #1 criteria. However, the Directory #1 criteria provide a reference point against which a Planning Coordinator’s **resource** adequacy criterion can be compared.

2.0 Purpose of Presentation

The purpose of the presentation associated with a **resource** adequacy review is to show that each Planning Coordinator's proposed **resources** are in accordance with the NPCC Directory #1 - Design and Operation of the **Bulk Power System**. By such a presentation, the Task Force will satisfy itself that the proposed **resources** of each NPCC Planning Coordinator will meet the NPCC **Resource** Adequacy Requirements, as defined NPCC Directory #1, over the time period under consideration.

3.0 Format of Presentation and Report – Comprehensive Review

Each Planning Coordinator should include in its presentations and in the accompanying report documentation, as a minimum, the information listed below. At its own discretion, the Planning Coordinator may discuss other related issues not covered specifically by these guidelines.

3.1 Executive Summary

3.1.1 Briefly illustrate the major findings of the review.

3.1.2 Provide a table format summary of major assumptions and results.

3.2 Table of Contents

3.2.1 Include listing of all tables and figures.

3.3 Introduction

3.3.1 Reference the previous NPCC Area Review.

3.3.2 Compare the proposed **resources** and **load** forecast covered in this NPCC review with that covered in the previous review

3.4 **Resource** Adequacy Criterion

3.4.1 State the Planning Coordinator's resource adequacy criterion.

3.4.2 State how the Planning Coordinator criterion is applied; e.g., **load** relief steps.

3.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts. In the calculation of available **resources**, supply-side **resources** from neighboring systems are limited to firm **capacity** backed purchases.

3.4.4 Provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria, if the Planning Coordinator criterion is different from the NPCC criterion

3.5 Resource Adequacy Assessment

3.5.1 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity **demand** assuming the Planning Coordinator's most likely **load** forecast.

3.5.2 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity **demand** assuming the Planning Coordinator's high **load** growth scenario.

3.5.3 Describe **load** and **resource** uncertainties on projected Planning Coordinator Area reliability and describe mechanisms to mitigate anticipated material adverse effects on reliability.

3.5.4 Describe anticipated effects from proposed major changes to market rules on Planning Coordinator Area reliability.

3.5.5 Summarize **resource** adequacy studies conducted since the previous Area Review, as appropriate

3.6 Reliability Impacts Due to Environmental Regulations and Fuel Supply Issues.

3.6.1 Discuss anticipated material adverse effects on reliability resulting from the proposed **resources** fuel supply and transportation.

3.6.2 Discuss anticipated reliability impacts related to an Area's compliance with State, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

3.7 Mitigation Measures for Environmental Regulations and Fuel Supply Issues

3.7.1 Describe available mechanisms to mitigate anticipated reliability impacts of **resource** fuel supply, **demand resource** response, fuel transportation issues and/or environmental considerations.

4.0 Format of Presentation and Report – Annual Interim Review

The Annual Interim Review should include a reference to the most recent Comprehensive Review; a listing of major changes in: facilities and system conditions, **load** forecast, **generation resources** availability; related fuel supply and transportation information, environmental considerations, **demand** response programs, transfer capability and emergency operating procedures. In addition, the assessment should also include a comparison of major changes in market rules, implementation of new rules, locational requirements, and installed **capacity** requirements. Finally, the report should include a brief impact assessment and an overall summary.

The Planning Coordinator will provide a brief assessment of the impact of these changes on the reliability of the interconnected **bulk power system**. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies. To the extent that engineering judgment or existing studies can be used to clearly demonstrate that a Planning Coordinator Area is expected to meet the NPCC **resource** adequacy criterion, detailed system LOLE studies are not required.

The documentation for the Annual Interim Review should be in the form of a summary report (normally not exceeding three to five pages.)

Sections A and B should describe the reliability model and program used for the **resource** adequacy studies discussed in Section 3.5. Section C should describe the Task Force follow-up procedures.

A. Description of Resource Reliability Model

1.1 **Load** Model

1.1.1 Description of the **load** model and basis of period **load** shapes.

1.1.2 How **load** forecast uncertainty is handled in model.

1.1.3 How the electricity **demand** and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

1.1.4 How the effects (**demand** and energy) of **demand**-side management programs (e.g., conversion, interruptible **demand**, direct control **load** management, **demand** (**load**) response programs) are addressed.

1.2 Supply Side **Resource** Representation

1.2.1 **Resource** Ratings

1.2.1.1 Definitions.

1.2.1.2 Criteria for verifying **ratings**. Reference NPCC Directory#9 Verification of Gross and Net Real Power Capability and Directory#10 Verification of Gross and Net Reactive Power Capability.

1.2.2 Unavailability Factors Represented

1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.

1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units

1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation

1.2.3.1 Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area Reliability Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.

1.4 Modeling of Variable and Limited Energy Sources.

1.5 Modeling of **Demand** Side **Resources** and **Demand** (**Load**) Response Programs.

1.5.1 Description should include how such factors as in-service date uncertainty, **rating**, availability, performance and duration are addressed.

1.6 Modeling of all **Resources.**

1.6.1 Description should include how such factors as in-service date uncertainty; **capacity** value, availability, **emergency** assistance, scheduling and deliverability are addressed.

1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.

1.8 Incorporate the reliability impacts of market rules.

B. Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation

The documentation required to meet the requirements of the above format should be in the form of summaries of studies performed within a Planning Coordinator Area, including references to applicable reports, summaries of reports or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Planning Coordinator has made a presentation or a series of presentations to the Task Force on Coordination of Planning, the latter shall:

1.1 Prepare a brief summary of key issues discussed during the presentation.

1.2 Note where further information was requested and the results of such further interrogations.

1.3 Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.

1.4 Recommend to the Reliability Coordinating Committee whether the **Resource** Adequacy Review is suitable for approval.

Appendix E - Guidelines for Requesting Exclusions to Simultaneous Loss of Two Adjacent Transmission Circuits on a Multiple Circuit Tower.

1.0 Introduction

Directory #1 allows for requests for exclusion from the simultaneous loss of two adjacent transmission circuits on multiple circuit towers on the basis of acceptable risk. All exclusions must be reviewed by the applicable Task Forces and approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to the Criteria includes the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;

2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or atmospheric conditions, or any other factors that influence the risk of sustaining the loss of adjacent transmission circuits on a multiple circuit tower;

2.3 An assessment of the consequences of the loss of adjacent transmission circuits on a multiple circuit tower, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** on the **bulk power system** ;

2.4 For existing facilities, the historical outage performance, including cause, for such **contingencies** on the specific facility (facilities) involved as compared to that of other multiple circuit tower facilities;

2.5 For planned facilities, the estimated frequency of adjacent transmission circuit multiple circuit tower **contingencies** based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

The following procedure is used to obtain an exclusion:

3.1 The entity requesting the exclusion (the Requestor) submits the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor's own Planning Coordinator, if such process is applicable.

3.2 TFSS reviews the request, verifies that the documentation requirements have been met, and determines the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS requests the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor provides copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor provides this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If all Task Forces deem the request for exclusion acceptable, the TFSS will forward a recommendation for approval to the RCC.

3.5 Exclusion requests will be effective upon approval by the RCC.

Appendix F – Procedure for Operational Planning Coordination

1.0 Introduction

The Reliability Coordinators (RC) of the Northeast Power Coordinating Council, Inc. (NPCC) require access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC **bulk power system**. All users of the electric systems, including market participants, should supply such data to the NPCC Reliability Coordinators. Coordination among and within the Reliability Coordinator Areas (RC Area) of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions should be transmitted by the NPCC RC Areas to other RC Areas as needed to assure reliable operation of the **bulk power system**. One aspect of this coordination is to ensure that adjacent RC Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and system **protection**, including Type I **special protection system,** outages that may materially reduce the ability of an RC Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another RC Area. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding **load**/**capacity** forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those **elements** that may have an adverse impact on other RC **Area(s)**. It also details general action that may be taken to improve the communication of problems as well as specific topics that may be discussed in regularly scheduled conference calls or ad -hoc conference calls arranged in anticipation of problems such as **capacity** deficiency or inadequate light **load** margin in one or more RC Areas.

NPCC participants and other recipients of the information provided by processes in this guideline should adhere to the NPCC Critical Energy Infrastructure Information Non – Disclosure agreement.

2.0 Load/Capacity Forecasts

2.1 Twice yearly by May 15th and November 15th respectively, the Operations Planning Working Group (CO 12) will perform a summer and winter assessment for the next season.

The results will be reviewed by the NPCC TFCO and the NPCC Reliability Coordinating Committee (RCC) during the spring and autumn meetings of both groups and documented in the summer and winter NPCC Reliability Assessment reports.

2.2 Each week, each RC Area will review its weekly net **resource capacity** margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC **Areas**. If an NPCC RC Area identifies a deficiency or light **load** condition, the RC **Area** should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

3.1 Each RC **Area** should exchange current and expected generator outages that may have a significant impact on an adjacent RC **Area** or neighboring systems or a significant impact on the transfer capability between RC **Areas.**

4.0 Transmission Outage Coordination

4.1 <u>Advance Planning of Transmission Facility Outages</u>

Each RC should exchange critical transmission **element** outages as identified in the coordination agreements with their interconnected neighbors, **elements** identified on the Facilities Notification List and multiple transmission **element** outages that may have an adverse impact on external energy transfers. Each Reliability Coordinator shall minimize the duration of outages to facilities that impact inter-Reliability Coordinator Areas.

4.2 <u>Facilities Notification List</u>

The NPCC Facilities Notification List, Attachment D, has two components:

1) the NPCC Transmission Facilities Notification List; and
2) the list of NPCC Type I **special protection systems**.

The Facilities Notification List is developed by each RC Area and specifies all facilities that, if removed from service, may have a significant, direct or indirect impact on another RC Area's transfer capability. The cause of such impact might include stability, voltage, and/or thermal considerations.

Prior to October 1st of each year, each RC Area will review and update its Facilities Notification List and coordinate necessary changes with other appropriate NPCC RC Areas. Prior to January 1st, and after review by the TFCO, the jointly developed, updated and approved Facilities Notification List will be posted on the NPCC secure website.

It should be noted that revisions to the Facilities Notification List will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

A temporary reconfiguration of the network may result in an outage to one or more facilities not listed in Attachment D having an impact on other NPCC RC Areas. It is the responsibility of the RC experiencing the condition to notify impacted RCs in a timely manner and provide updated status reports during the condition.

4.3 <u>Notifications of Transmission **Element** Outages:</u>

4.3.1 Notification requirements for Transmission **Element** Outages should be defined in interconnection coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 Reliability Coordinators will advise affected RCs of all planned and unplanned outages of **elements** on the Facilities Notification List and those multiple transmission **element** outages that may have an adverse impact on external energy transfers.

All outages to equipment listed in the Facilities Notification List and those multiple transmission **element** outages that may have an adverse impact on external energy transfers should be planned with as much advance notice as practical.

Normally, notification for outages on **elements** covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the **element** is to be taken out of service.

When an RC Area receives an outage notification from another RC Area, prompt attention will be given to the notification and appropriate comments rendered.

4.3.3 An RC Area will not normally remove from service any transmission **elements,** which might have a **reliability** impact on an RC Area without prior notification to and appropriate review by that RC Area. In the event of an **emergency** condition, each RC Area may take action as deemed appropriate. Other RC Areas should be notified immediately.

An RC Area will make every effort to reschedule routine (non-emergency) transmission outages that severely degrade the reliability of an adjacent RC Area or neighboring system.

4.3.4 Each RC Area will advise the other affected RC Areas of any **protection** outage associated with RC Area tie line facilities Coordination agreements may identify additional reporting requirements associated with **protection** outages.

5.0 Specific Communications

Conditions in an RC Area that may have an impact on another RC Area should be communicated in a clear and timely manner. Specific communications are conducted as follows:

5.1 Weekly

Each Thursday a conference call will be initiated by the NPCC Staff to discuss operations expected during the seven-day period starting with the following Sunday. Operations personnel from the NPCC RC Areas and, as necessary, adjacent RC Areas will participate. In advance of the conference call, each RC Area will prepare the data specified in Attachments A and B, and forward it to the NPCC Staff a minimum of one hour in advance of the scheduled call. The completed "NPCC Weekly Conference Call Generating **Capacity** Worksheet," Attachment B, together with the list of "Twelve Weeks Projections of Net Margins," will be forwarded to the conference call participants by the NPCC Staff.

Each RC will review its weekly **capacity** margins for the next twelve week period. If a deficiency or light **load** condition is identified, the RC will identify the cause of the deficiency or light **load** condition and discuss proposed mitigation measures.

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.

Items of particular concern that should be addressed during the weekly conference call are described in Attachment C.

5.2 Emergency Preparedness Conference Call

Whenever adverse system operating or weather conditions are expected, any RC Area may request the NPCC Staff to arrange an Emergency Preparedness Conference Call (NPCC Document C-01) to discuss operating details with appropriate operations management personnel from the NPCC RC Areas and neighboring systems.

5.3 Daily Conference Calls

Each of the NPCC Reliability Coordinator Area control rooms participate in a regularly scheduled daily conference call. The goal of this call is to alert NPCC Reliability Coordinators of any potential emerging problems. Subjects for discussion are limited to credible events which could impact the ability of a

Reliability Coordinator to serve its **load** and meet its operating reserve obligations, or which would impose a burden to the Interconnection.

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions and Generating Capacity Worksheet Instructions

Week Beginning	The seven day period for which data is to be reported is defined as starting with the Sunday following the conference call through the following Saturday.
Installed Generating Capacity (Line Item 1)	Include all available **generation** at its maximum demonstrated capability for the appropriate seasonal capability period.
Other Generating Capacity(Line Item 2)	Include all available **generation** not included in Item#1. This item includes, but is not limited to, co-generators, small power producers and all other non-utility electricity producers, such as exempt wholesale generators who sell electricity.
Firm Purchases (Line Item 3)	Include only those transactions where **capacity** is delivered. Exclude “energy only” transactions.
Firm Sales (Line Item 4)	Include only those transactions where **capacity** is delivered. Exclude “energy only” transactions.
Net Capacity (Line Item 5)	Add Installed Generating **Capacity** and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 6)	The peak **load** forecast along with the day during which the peak is expected to occur should be the best estimate of the RC Area’s maximum peak **load** exposure anticipated for the week reported.
Available Reserve (Line Item 7)	Subtract Peak **Load** Forecast from Net **Capacity**. (Line 4-Line5.)
Demand Side Management (Line Item 8)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capacity (Line Item 9)	Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include **capacity** unavailable due to transmission constraints.
Net Reserve (Line Item 10)	Available Reserve plus **Demand** Side Management minus Known Unavailable **Capacity**. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 11)	The methodology used by each RC Area in calculating operating reserves should, at a minimum, meet the requirements of NPCC Directory # 5, "Reserve." Methodologies differing from the Directory #5 requirements should be clarified in Attachment B, "NPCC Weekly Conference Call Generating **Capacity** Worksheet," under the tab for "Operating Reserve."
Gross Margin (Line Item 12)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 13)	Estimate the amount of generating **capacity** which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
Net Resource Capacity Margin (Line Item 14)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 15)	Include the expected high and low temperatures for the RC **Area** for the week, and indicate the day on which they are expected to occur.

Attachment A (continued)	
Seasonal High / Low Temperatures (Line Item 16)	Include the expected high and low forecast seasonal temperatures for the RC **Area**.
Minimum Load Forecast (Line Item 17)	The minimum **load** forecast, indicating the day on which it is expected to occur should be the best estimate of the RC Area's minimum **load** exposure anticipated for the week reported.
Minimum Resources (Line Item 18)	The Minimum **Resources** are the Reliability Coordinator **Area's** total expected on-line generator minimum output capability and must-take purchases.
Light Load Margin (Line Item 19)	Subtract Minimum **Resources** from Minimum **Load** Forecast. A negative number indicates a light **load** condition. (Line 17-Line 18)

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

The "NPCC Weekly Conference Call Generating **Capacity** Worksheet" is an active spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template is available from the NPCC office.

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call can include, but are not limited to, the following:

- anticipated weather;
- largest first and second contingencies;
- operating reserve requirements and expected available operating reserve;
- **capacity** deficiencies;
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls;
- light **load** margins;
- general and specific voltage conditions throughout each system or RC Area;
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves;
- additional capability available within twelve hours and four hours;
- generator outages that may have a significant impact on an adjacent RC **Area** or neighboring system;
- transmission outages that may have an adverse impact on external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay **protection** schemes so that the usual and customary levels of **protection** will not be provided, or the arming of **special protection systems** not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I **special protection systems** forced out of service

Attachment D

NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

This Procedure provides general principles and guidance to Reliability Coordinators and Transmission Operators for effective inter- Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, "Design and Operation of the **Bulk Power System**". Specific methods to implement this Procedure may vary among Reliability Coordinators and Transmission Operators, depending on local requirements. Coordinated inter- Transmission Operator Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Reliability Coordinators and Transmission Operators can assist each other to compensate for deficiencies or excesses of **reactive power** and improve voltage profiles and system security.

2.0 Principles

Each Reliability Coordinator and Transmission Operator operates, in accordance with NPCC, Directory #1, "Design and Operation of the **Bulk Power System**" criteria, their own individual or joint operating policies, procedures and applicable interconnection agreements. Adjacent Reliability Coordinators and Transmission Operator should be familiar with the respective criteria and procedures of their neighboring Reliability Coordinators and Transmission Operator Areas, and should mutually agree upon procedures for inter- Transmission Reliability Coordinator and Operator Area voltage control.

In the event the system state changes to a condition that requires a voltage or reactive corrective action, the Reliability Coordinator and Transmission Operator for the Area in which the condition is originating from should immediately take corrective action. If the corrective control actions are ineffective, or the Reliability Coordinator and Transmission Operator for the Area have insufficient reactive **resources** to control the problem, assistance may be requested from other Reliability Coordinators and Transmission Operator Areas.

Whether inter- Reliability Coordinator and Transmission Operator **Area** voltage control is carried out through specific or general procedures, the following should be considered and implemented if applicable:

2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power resources** and voltage controller status should be the same between adjacent Reliability Coordinators and Transmission Operator Areas;

2.2 the availability of **voltage regulating transformers** in the proximity of **tie lines**;

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter- Reliability Coordinator and Transmission Operator **Area** interface;

2.4 the circulation of **reactive power** (export at one tie point in exchange for import at another);

2.5 **tie line** reactive losses as a function of active **power** transfer;

2.6 the sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.);

2.7 the transfer of **reactive power** from one Reliability Coordinator and Transmission Operator Area to another

2.8 reactive **reserve** of on-line generators;

2.9 shunt reactive device availability and switching strategy;

2.10 **static VAR compensator** availability, reactive **reserve**, and control strategy;

2.11 each Reliability Coordinator and Transmission Operator Area should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads.**

2.12 Each Reliability Coordinator and Transmission Operator Area should maintain a mix of static and dynamic **resources**, including reactive **reserves**

3.0 Procedure for Triennial Monitoring and Reporting of Inter-Area Voltage Control

3.1 On, or shortly before, the first of July, the Task Force Coordination of Operations (TFCO) Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:

a) A copy of any new or revised procedures, principles, or understandings (such as minutes of an operating committee meeting between Reliability Coordinators and Transmission Operator Areas) between the reporting Reliability Coordinator and adjacent Reliability Coordinators, or,

b) a response indicating no change to existing procedures, principles, or understandings currently on file at NPCC.

3.2 The TFCO Secretary will summarize the responses and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

3.3 Following TFCO review and acceptance of the responses, the TFCO Chairman will forward the summary to the Chairman of the Reliability Coordinating Committee (RCC) for informational purposes. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.

PUBLIC

IMP_POL_0002

POLICY

Market Manual 7: System Operations

Market Manual 7.4: IESO-Controlled Grid Operating Policies

Issue 35.0

This document provides policy statements for reliable operation of the *IESO-Controlled grid.*

Disclaimer

Document ID	IMP_POL_0002
Document Name	Market Manual 7.4: IESO-Controlled Grid Operating Policies
Issue	Issue 35.0
Reason for Issue	Issue released for Baseline 37.1
Effective Date	June 7, 2017

Document Change History

Issue	Reason for Issue	Date
For document change history prior to 2011, refer to versions 24.0 and prior.		
23.0	Issue released for Baseline 27.0	March 7, 2012
24.0	Issue released for Baseline 27.1	June 6, 2012
25.0	Issue released for Baseline 28.0	September 12, 2012
26.0	Issue released in advance of Baseline 31.0 for the implementation of SE-109: Outage Management Process Redesign and Market Rule Amendment MR-00404-R00.	February 5, 2014
27.0	Issue released for Baseline 31.1	June 4, 2014
28.0	Issue released for Baseline 32.0	September 10, 2014
29.0	Issue released for Baseline 32.1	December 3, 2014
30.0	Issued in advance of Baseline 33.1 to update IESO logo.	March 31, 2015
31.0	Issue released for Baseline 34.1	December 2, 2015
32.0	Issued in advance of Baseline 35.0	December 17, 2015
34.0	Issue released for Baseline 36.0	September 14, 2016
35.0	Issue released for Baseline 37.1	June 7, 2017

Related Documents

Document ID	Document Title
MDP_PRO_0040	Market Manual 7.1: IESO-Controlled Grid Operating Procedures

Table of Contents

List of Figures

List of Tables

Table of Changes

Reference (Section and Paragraph)	Description of Change
Throughout	Repaired broken hyperlinks.
Section 4.3.10 and Appendix B	Updated references from “best effort basis” to “reasonable effort basis” in order to better express the intent of the relevant provisions. This change does not impact IESO operations priorities.

Market Manuals

The *market manuals* consolidate the procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-controlled grid* and *IESO-administered markets.* Procedures provide more detailed descriptions of the requirements for various activities than is specified in the *market rules*. Where there is a discrepancy between the requirements in a document within a *market manual* and the *market rules*, the *market rules* shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

Market Policies

The System Operations Manual is Series 7 of the *market manuals*, where this document forms Part 7.4: *IESO*-Controlled Grid Operating Policies.

A list of the other component parts of the “System Operations Manual” is provided in Market Manual 7.0: System Operations Overview.

Conventions

The *market manual* standard conventions are as defined in the Market Manual 7.0.

When a series of actions are indicated these shall be taken in the most effective order to safeguard the *reliability* of the *IESO-controlled grid*. If the order of a series of actions shall not be altered, then this shall be indicated.

– End of Section –

1. Introduction

1.1 Purpose

This document contains *IESO* policies for reliable operation of the *IESO-controlled grid*. These policies are intended to:

- Provide guidance for the development of *IESO* procedures,
- Provide guidance to *IESO* operating staff when confronted with an operational situation that is not addressed in an operating procedure or a *market rule, and*
- Help *market participants* meet their obligations to the *IESO* in the operating time horizon*.*

To the extent practicable, the *IESO* will use available market mechanisms to direct reliable operation of the *IESO-controlled grid*. Where the *IESO* determines such mechanisms are unable to achieve reliable operation, it will take actions in accordance with the policies contained in this manual.

1.2 Hierarchy

Operating policies shall conform to the *Electricity Act 1998, market rules*, *NERC reliability standards* and *NPCC* directories. When the interpretation of an *IESO* operating policy is in question, *IESO* staff shall select the interpretation most consistent with the *market rules*. When the proper interpretation of a *NERC* standard is in question, *IESO* staff shall select the interpretation most consistent with the purpose of the standard and NERC's objects to maintain the minimum level of reliability. When the proper interpretation of *NPCC* criteria is in question, *IESO* staff shall select the interpretation most consistent with NPCC's reliability objects.

The operating policies of this manual are built on the foundation that Ontario's power system is planned and designed in accordance with the *Ontario Resource and Transmission Assessment Criteria (ORTAC)*. Where existing equipment is insufficient to satisfy *ORTAC* criteria, special practices shall be documented in operating instructions and followed until the required equipment is in operation.

In case of a discrepancy between this *market manual* and another *manual* in the *Market Manual* 7 series, the policies of this *market manual* shall apply. In case of discrepancy between this document and a more stringent *reliability standard*, the *reliability standard* shall apply.

1.3 Scope

These policies apply to the *IESO* in its role to fulfill its legislated objects to direct the operation and maintain the *reliability* of *IESO-controlled grid* and to establish and enforce criteria and standards related to the reliability of the *integrated power system*.

Operating policies will be applied to facilities connected to the *IESO-controlled grid*.

Procedural details necessary to implement these policies are outside of the scope of this document. These details shall be found in the applicable manual of the M*arket Manual* 7 series.

1.4 Roles and Responsibilities

1.4.1 Principles

The responsibility for directing the operation and maintaining the *reliability* of the *IESO-controlled grid* is assigned to the *IESO* in the *Electricity Act, 1998,* Section 5(c) and in *Market Rule* Chapter 5, Section 3.2, (MR Ch. 5 Sec. 3.2) and is a condition of the *IESO License*. The *IESO* develops and maintains the policies and procedures necessary to meet this responsibility as well as monitor and enforce compliance with applicable *reliability standards.*

The *IESO* directs its operation within the framework of the *market rules, market manuals, operating agreements*, *interconnection agreements* and other operating documentation.

The *IESO* recognizes the authority of a *market participant* to take independent action to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*.

1.4.2 IESO Responsibilities

IESO staff must adhere to the policies defined in this document when operating the *IESO-controlled grid*. Staff will:

- Take all material actions required to maintain at least the minimum acceptable level of *reliability*. The minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition limits.
- Establish and interpret *System Operating Limits (SOLs)* and verify their accuracy
- Identify operating conditions (e.g., High Risk, Normal, *Emergency*, etc.) under which a particular *SOL* will be implemented.

The *IESO* is responsible for maintaining the *reliability* of the *IESO-controlled grid* and to achieve this efficiently through *the IESO-administered markets*. To the extent necessary to maintain *reliability*, the *IESO* shall intervene in *IESO-administered markets*. For example, the *IESO* will produce *SOLs* that accurately reflect a studied operating state. However, when reacting to an unstudied operating state, the *IESO* will give precedence to system *security* over market efficiency (e.g., by formulating *SOLs* on a conservative basis until time permits more detailed assessments).

1.5 Document Layout

The *IESO* is primarily responsible for *system security and adequacy*.

Adequacy	The ability of the power system to supply the electrical *demand* on the system, taking into account scheduled and reasonably expected unscheduled *outages* of system elements.
System security	The ability of the power system to withstand sudden disturbances or unanticipated loss of elements.

Section 2: Reliability covers policies that affect both *system security* and *adequacy.*

Section 3: Adequacy covers policies that ensure an **adequate** system.

Section 4: System Security covers policies that ensure a **secure** system.

1.6 Contact Information

Changes to this public *market manual* are managed via the *IESO* Change Management process. Stakeholders are encouraged to participate in the evolution of this *market manual* via this process.

To contact the *IESO*, you can email *IESO* Customer Relations at customer.relations@ieso.ca or use telephone or mail. Telephone numbers and the mailing address can be found on the IESO website (http://www.ieso.ca/corporate-ieso/contact). Customer Relations staff will respond as soon as possible.

– End of Section –

2. Reliability

2.1 Principles

The *IESO-controlled grid* shall operate at a level of *reliability* such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of *reliability* is achieved by operating the *IESO-controlled grid* to meet *adequacy* criteria for anticipated *demand*, system *security* criteria for specified contingencies, and re-preparation criteria for restoring *reliability* following contingencies.

IESO legacy practices that are more stringent than required by external *standards authorities* will be continued until the *IESO*, in consultation with stakeholders, determines these practices are no longer justified.

Where the *IESO* determines that *reliability* criteria more stringent than required by external *standards authorities* are required to reliably operate the power system, the *IESO* will develop these criteria in consultation with *transmitters*, *market participants*, and other stakeholders. The *IESO* will *publish* these more stringent *reliability* criteria and operate in accordance with them.

2.2 Communications

2.2.1 Policies

IESO communication procedures shall comply with *NERC reliability standards* and *NPCC* directories related to communications. *IESO* requirements for communications are published in *Market Manual* 7.1: System Operations Procedures.

2.3 Outage Management

2.3.1 Principles

When assessing proposed *outages* of *market participant registered facilities* and associated equipment, the *IESO* shall base outage approval solely on maintaining reliable operation (including overall *adequacy* and operability) of the *IESO-controlled grid* (MR Ch. 5 Sec. 6.2 – 6.4B). The *IESO* shall reject, revoke, or recall an *outage* if it presents a *risk* to the reliable operation of the *IESO-controlled grid*.

Reliability standards do not impose an absolute requirement to maintain a continuous supply of electricity to any specific customer.

2.3.2 Policy

The *IESO* shall deal fairly and appropriately with *market participants,* and comply with the applicable *market rules* and *market manuals*. The *IESO* will provide *market participants* with timely and accurate information regarding the *IESO-controlled grid* to facilitate *market participant* coordination of *outages* and provide mechanisms to resolve *outage* conflicts.

The *IESO* shall coordinate *outages* to equipment external to Ontario with authorities in neighbouring jurisdictions to meet *NERC* and *NPCC* obligations, and to satisfy *IESO operating agreements* with interconnected neighbours. The *IESO* will NOT coordinate *outages* to individual customer connections. This obligation rests with the associated *transmitter.*

For switching configurations expected to last not more than 15 minutes, the only system *security* criteria that will be observed are:

- Equipment loading shall be within pre-contingency ratings supplied by asset owners, and
- Transfers shall be restricted to prevent pre-contingency voltage collapse.

The *IESO publishes* and maintains a *market manual* for *outage management* of *facilitie*s and equipment connected to the *IESO-controlled grid*, or which may affect the operation of *the IESO-controlled grid*. Refer to Market Manual 7.3: Outage Management.

2.4 Grid Operating States

2.4.1 Principles

The three common operating states in order of system *security* are high-risk (including safe posture), normal, and *emergency*. There are other operating states, such as system restoration (Section 4.5), which occurs immediately following a contingency.

Under certain operating conditions (e.g., adverse weather or equipment-related problems), the probability of experiencing certain contingencies (or the severity of associated consequences) increases. The *IESO* shall temporarily and selectively increase the level of system *security* to improve *reliability* during these *high risk operating states*.

Under other conditions (e.g., anticipating or experiencing *energy* deficiencies or capacity deficiencies, or operating in an unstudied operating state), *non-dispatchable load* shedding may be required. The *IESO* strives to mitigate or avoid *non-dispatchable load* shedding when in these *emergency operating states* by publishing and maintaining a hierarchy of control actions to be taken in anticipation of (and after the declaration of) an *emergency operating state*. Refer to the Emergency Operating State Control Actions (EOSCA) list in Market Manual 7.1: IESO-Controlled Grid Operations Procedures*,* Appendix B.

In high-risk and *emergency operating states*, *IESO* control actions are structured to:

1. Preserve system *reliability.*
2. Restore normal operation of *IESO-administered markets* as soon as practicable (*MR* Ch 5, Sec. 7.7.2).

The *IESO* will strive to mitigate adverse effects on *IESO-administered markets*, while at the same time observing the mutual protection and assistance provisions contained in agreements between the *IESO* and other *reliability coordinators* and *balancing authorities.*

2.4.2 High-Risk Operating State

In a *high-risk operating state*, the *IESO* will temporarily and selectively increase the level of *system security* by applying high-risk operating limits. The *IESO* will take actions such as rejection, revocation, or recall of equipment and *facility outages* when necessary to:

- Maintain the level of *system security* required during a *high-risk operating state*, and

- Allow, after a recognized contingency, the *IESO* to re-establish an acceptable level of *system security* and to re-prepare the *IESO-controlled grid* within the time permitted by *reliability standards*.

The conditions under which a *high-risk operating state* may be declared (along with related policy implementation details) can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.4.3 Normal Operating State

In a *normal operating state,* the *IESO* will supply all *non-dispatchable loads* while operating to normal condition limits.

The *IESO* shall direct *market participants* to act or to refrain from acting so as to maintain the *IESO-controlled grid* in a *normal operating state* (MR Ch. 5 Sec. 2.2). The *IESO* will also act or refrain from acting where doing otherwise is likely to lead to a *high-risk* or *emergency operating state* (MR Ch. 5 Sec. 2.3.2, 2.4.2, and 5.1.2.6).

2.4.4 Emergency Operating State

The *IESO* strives to mitigate or avoid *non-dispatchable load* shedding when in an *emergency operating state* by publishing and maintaining a hierarchy of control actions to be taken in anticipation of and after the declaration of an *emergency operating state* (refer to the EOSCA list in *Market Manual 7.1*). Temporarily and selectively reducing the level of *system security* by applying emergency condition operating limits is one of the many control actions the *IESO* can take when in an *emergency operating state*.

At all times, the minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load*, to observe the emergency condition operating limits.

An *emergency operating state* will generally not be declared when normal or routine control actions can resolve the capacity or *energy* deficiency, or return the *IESO-controlled grid* to a studied operating state in a timely manner. Implementation details, including the conditions under which an emergency *operating state* may be declared can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.5 Degraded Transmission Equipment Performance

A higher than long-term average *forced outage* rate, unanticipated tripping, or unanticipated failure to trip are typical examples of degraded transmission equipment performance. Where transmission equipment has shown degraded performance, or if degraded performance is anticipated, the *IESO* shall take control actions such as the following:

- Reschedule routine maintenance work, except work to remedy degraded performance,
- Reject or revoke any *planned outages* with Planned, Opportunity, or Information Priority Code anticipated to have an adverse impact on the *IESO-controlled grid,* except for *planned outages* to remedy degraded performance*,*

- Recall any *planned outages* with Planned, Opportunity, or Information Priority Code that may have an adverse impact on the *IESO-controlled grid* associated with the affected portion of the *transmission system,*
- Request staffing at transmission stations during periods of routine switching, during periods of high risk of equipment operation, or on a 24/7 basis depending on the severity of equipment degradation,
- Adjust *IESO system security* assessments to account for additional elements anticipated to be removed from service due to equipment degradation,
- Adjust use of *Remedial Action Schemes* to reduce operation of affected *transmission system* equipment, or
- Direct *generators* and other *market participants* as required to enhance *reliability.*

Where time permits, the *IESO* will discuss control actions with the applicable *transmitter* before implementation. Affected *market participants* and *reliability coordinators* shall be advised as appropriate, which may include publishing information on areas with degraded transmission equipment performance.

2.6 Islanding

The *IESO* shall notify *generators* of *outages* that would put their units in an electrical island following a single element contingency to inform their operating decisions.

The *IESO* shall NOT manually constrain down resources pre-contingency in order to assist a rapid collapse of an electrical island. When determining whether an island will survive or collapse, the *IESO* shall assume that inverter-based generation (i.e., wind and solar) will immediately trip in an electrical island where conventional synchronous units cannot meet *demand* in the island.

The *IESO* shall NOT manually constrain up resources pre-contingency in order to assist the survival of an electrical island.

The *IESO* shall take available pre-contingency control actions (other than constraining resources, such as a configuration change or *RAS* arming) to assist the rapid collapse of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will not be controlled within acceptable ranges, **or**
- *IESO* cannot obtain voltage and frequency measurements in the island.

The *IESO* shall take available pre-contingency control actions (other than constraining resources, such as a configuration change or *RAS* arming) to assist the survival of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will be controlled within acceptable ranges, **and**
- *IESO* can obtain voltage and frequency measurements in the island.

The *IESO* shall synchronize islands only by using breakers that have synchrocheck relays, or a mechanism of ensuring that the circuit breaker closes only if voltages on both sides of the circuit breaker fulfill conditions of magnitude, phase, and slip frequency.

If special islanding practices are developed that differ from the above general policy, these practices shall be documented in operating instructions.

2.7 Grid Control Actions

2.7.1 Principles

The objective of the *IESO-administered markets* is to promote an efficient, competitive, and reliable market for the wholesale purchase and sale of electricity and *ancillary services* in Ontario (MR Ch. 1 Sec. 3.1.1).

To satisfy this objective, all practicable control actions shall be taken to move towards an unconstrained *dispatch* while observing all *system security* or *adequacy* constraints.

2.7.2 Readiness Programs

To maintain confidence that control actions will be available when called upon (MR Ch. 5 Sec. 4.6.2), the *IESO* shall test or require *market participants* to test facilities that are connected to the *IESO-controlled grid*. This testing could be to prepare for the next peak season, or to prepare for extreme conditions that are expected in the next few days. For example, voltage reduction, *operating reserve* activation, and reactive capability will be periodically tested.

IESO readiness program implementation details can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.7.3 Network Configuration Change Request

The *IESO* shall assess proposed network configuration requests to manage individual *delivery point* performance and, through the *outage* management process, approve proposals that do not:

- Degrade the *reliability* of the *IESO-controlled grid*,
- Reduce an SOL or transfer capability,
- Result in inconsistent application of established system *security* criteria and *reliability standards*,
- Impose additional exposure to loss of essential station service supply to nuclear generating stations,
- Expose the *IESO-controlled grid* to additional contingencies that have a material adverse effect on the *reliability* of the *IESO-controlled grid*,
- Impose additional risk/restrictions related to post-contingency response to recognized contingencies, and
- Interfere with the operation of *IESO-administered markets* (i.e., do not result in changes in generation dispatch, *market clearing price,* or congestion payments).

During normal situations, the *IESO* will include such advance-approved proposals in its operating instructions ahead of real-time operations.

During abnormal situations (e.g., *forced outages*, responding to contingencies, system restorations, etc.), the *IESO* may deviate from the above provisions while respecting their intent to the extent possible.

2.7.4 Control Actions to Increase Transfer Capability

To increase transfer capability to improve *reliability* and/or reduce congestion costs, the *IESO* will assess and may implement control actions such as:

- Changing reactive *dispatch*,
- Changing transformer winding or phase angle taps,
- Load transfers,
- Arming *remedial action schemes (RASs)*,
- Manually constraining generation up or down,
- Opening breakers or switches, including high or low voltage bus tie breakers,
- Taking equipment off load, or
- Removing equipment from service.

The applicable *transmitter* must concur with a control action that will reduce connection redundancy, or transfer load where *delivery point* performance is substandard.

The *IESO* will implement these control actions, or include them as part of its operational planning assessment of *outage* requests, unless the action:

- Fails to conform to a policy contained in this document,
- Exposes nuclear generating stations to loss of essential *station service* supply following an Appendix A, Group 1 contingency, or
- Causes post-contingency configurations expected to exceed system *security* restoration timelines.

2.7.5 Voltage Control

To maintain transmission line voltages within ranges, to respect *SOLs,* and to respect equipment ratings, the *IESO* will *dispatch* the following:

- *Generation unit* reactive power within unit capability,
- Reactive control devices subject to *operating agreements*, and
- Reactive control devices subject to procurement contracts.

The *IESO* will *dispatch* the following to meet *connected wholesale customer* or *distributor* voltage needs, as long as these actions do not exceed *SOLs* and equipment ratings:

- *Generation unit* reactive power within unit capability, and
- Reactive control devices subject to *operating agreements*.

2.7.6 Remedial Action Schemes

The *IESO-controlled grid system security* must be returned to a secure state within times prescribed by *reliability standards* following operation of a *RAS*. The IESO will direct the use of RAS as outlined in transmitter operating agreements.

A *RAS* shall not be deployed until it has been classified in the *NPCC* process as Type I, II, or III. A Type I *RAS* shall be deployed in a manner consistent with its description in the *NPCC* approval process. Usually a Type I RAS is approved for deployment for *outage* conditions, for extreme contingencies, or for unanticipated operating conditions. Usually a Type II or Type III *RAS* is approved with fewer or no deployment restrictions.

Specific criteria for selection of load rejection (L/R), generation rejection (G/R), and generation runback are contained in Appendix B. The use of a *RAS* during a *high-risk operating state* shall be subject to the restrictions contained in Appendix C.

The *IESO* shall allow *market participants* to request an exclusion from L/R for the following reasons:

- Public safety hazard,
- Potential damage to equipment,
- Potential violation of any *applicable law*,
- Outages to equipment directly associated with L/R tripping or restoration, or
- Outages to equipment which may degrade the integrity of L/R tripping or restoration (such as, but not limited to, relaying or station supervisory control equipment).

The *IESO* shall direct the restoration of rejected load. Load may be restored following rejection by interrupting other load (i.e., rotating blackout) as a substitute.

2.7.7 Voltage Reductions

The *IESO* may direct a *market participant* to initiate voltage reductions to prevent or to mitigate an *emergency operating state* (MR Ch. 5 Sec. 10.1.1) resulting from events including:

- Equipment thermal overloads,
- Insufficient *generation capacity* to satisfy non-dispatchable demand,
- Violations of high-risk, normal, or emergency SOLs, or
- An event requiring the *IESO* to activate *operating reserve* that is provided by *voltage reductions*.

2.7.8 Non-Dispatchable Load Shedding

Shedding *non-dispatchable load* is a permissible *IESO* control action to maintain grid integrity, or to respect safety, equipment, or *applicable law* constraints.

When an *SOL* is exceeded, *non-dispatchable load* shedding may be avoided or deferred by taking the following steps as required:

1) **Disregard high-risk limits and apply normal limits.**

   This step will allow an increase in transfer limits constrained by *RAS* arming and other restrictions due to a *high risk operating state*.

2) **Disregard normal limits and apply emergency condition operating limits.**

   This step will allow an increase in transfer limits constrained by contingencies involving more than one element.

The *IESO* shall shed load during an *emergency operating state* under the following conditions:

- To alleviate a capacity or energy emergency,
- To alleviate or avoid exceeding equipment ratings, pre-contingency voltage collapse, or a steady-state instability, or
- To alleviate an Interconnection Reliability Operating Limit (IROL) exceedance.

Note that when a transfer is near its limit, both the limit and its associated boundary conditions (e.g., minimum voltage at Longwood, Bruce, etc.) are equally important considerations. As a transfer departs from its limit, boundary conditions become less important, and it may not be necessary to shed *non-dispatchable load* to address a boundary condition exceedance. Discretion to avoid shedding *non-dispatchable load* for a boundary condition exceedance is documented in operating instructions.

- **To bring the system back to a studied operating state**

  All necessary steps are to be taken, including the interruption of *non-dispatchable load*, to observe the emergency condition operating limits and return to a studied operating state.

When an *emergency operating state* has been declared and reduction in *demand* is required to safeguard the *reliability* of the *IESO-controlled grid*, the *IESO* shall direct manual load shedding to reduce *demand* on the following basis:

- Priority customer loads (refer to *Market Manual* 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup *generators*, and electrically driven gas compressors should be avoided when determining what load to shed.
- The amount and location of load to be cut will be selected to solve the operating problem to maintain an adequate level of *IESO-controlled grid adequacy* or *system security*.
- When time permits, load cuts via manual rotational load shedding schemes should be spread equitably across the *IESO-controlled grid* to the extent practicable. Equitable considerations will include magnitude, duration, and frequency of load reductions.

– End of Section –

3. Adequacy

3.1 Principles

The *IESO* shall maintain an adequate supply of generation and transmission to meet forecast Ontario *demand* in the operational timeframe. When assessing generation and transmission *adequacy*, the *IESO* will consider factors including the following:

- Demand forecast,
- *Variable generation* (e.g., wind and solar) forecast,
- Load forecast uncertainty,
- Additional contingency allowance,
- *Operating reserve* requirements,
- Generation and *demand response* availability forecast, which includes the available but not operating (ABNO) units, and generation external to Ontario and associated tie-line capability,
- Transmission *facility* capability forecast,
- Applicable *SOLs*, and
- Acceptable voltage ranges.

3.2 Resource and Transmission Adequacy

When assessing *adequacy*, the *IESO* shall compare forecasted *demand* to available resource capacity and *energy*, including available resources external to Ontario. The *IESO* shall assess *adequacy* for *normal operating states* on a daily basis in its short-term operating assessments, on a weekly basis in its medium-term assessments, and on a less frequent basis in longer-term assessments. For these operating horizons, criteria to identify an acceptable level of *adequacy* (and corrective actions if this level cannot be achieved), can be found in *Market Manual 7.2:* Near-Term Assessments and Reports.

When assessing transmission *adequacy*, the *IESO* shall compare transmission flow forecasts with the applicable *SOLs* under an anticipated range of power system conditions. Transmission is adequate if *demand* forecasts can be supplied without exceeding applicable *SOLs*, and acceptable system voltages can be maintained.

3.3 Operating Reserve Policy

Operating Reserve shall be scheduled (MR Ch. 5 Sec. 4.5.1) to ensure resources are available to:

- Cover or offset unanticipated increases in *demand* during a *dispatch day* or *dispatch hour*,
- Cover or offset capacity lost due to a *forced* or urgent *outages* of generation or transmission equipment, or
- Cover uncertainty associated with the performance of *generation facilities* or *dispatchable loads* in responding to *IESO dispatch* instructions.

Additional reserve shall be carried to account for an increased risk of tripping during commissioning tests. No additional *operating reserve* shall be required during a commissioning period when no tests are scheduled that materially increase the risk of unit tripping.

Operating reserve shall be scheduled in sufficient quantity and shall be distributed so as to ensure that it can be utilized for any single contingency that results in generation loss without exceeding equipment or *transmission system* limitations.

Voltage reduction may be used to provide *operating reserve*.

3.4 Area Reserve for Load Security

Area reserves (i.e., reserves that are scheduled or resources that are pre-committed to avoid shedding *non-dispatchable load*) shall be scheduled as follows:

- **For all *SOLs*:** All available resources shall be committed to avoid shedding *non-dispatchable load* before a contingency.
- **For IROLs:** Non-energy limited resources shall be pre-committed so that following a single-element contingency, the system can be re-prepared within 30 minutes to operate to IROL emergency contingency limits, without shedding *non-dispatchable load*.
- From time to time, the *IESO* may choose to carry additional area reserve beyond those required here for circumstances such as extreme weather forecasts, physical *security* threats, etc.

– End of Section –

4. System Security

4.1 Principles

This section describes the level of system *security* that must be achieved so that the risk of loss or separation of major portion of the *interconnected system* is reduced to an acceptable level.

The *IESO-controlled grid* must display satisfactory performance before and after *contingency events*. All *IESO* performance criteria must be satisfied, not only the transient and voltage stability criteria, for an operating condition to be deemed stable.

The *IESO-controlled grid* must be operated such that in a normal, planned state, voltages will be within normal limits, equipment loading will be within continuous ratings as supplied by *facility* owners, and transfers will be within *SOLs*. For *planned outages* with Planned, Opportunity, or Information Priority Code, equipment may be loaded to long-term *emergency* ratings if authorized by the facility owner. Operation within authorized ratings shall be considered sufficient to avoid physical damage, protect safety, and avoid violation of any *applicable law* unless otherwise notified.

The *IESO* will use the following policies to develop operational plans, establish *SOLs* and instructions, and operate the *IESO-controlled grid*.

4.2 Methodology for Deriving System Operating Limits

SOLs shall be established[1] by monitoring the system security criteria in Section 4.3 on Bulk Power System (BPS), Bulk Electric System (BES), and Local elements in the following manner:

1. On BPS elements, the system security criteria shall be satisfied for any Appendix A Group 1 contingency occurring anywhere in Ontario. As Group 1 includes multiples, this fulfills requirement R3.3 of *NERC* standard FAC-011. The monitoring of all Group 1 contingencies in Ontario on BPS elements satisfies *NPCC* Directory #1 R13.
2. On BES elements, the system *security* criteria shall be satisfied for any Appendix A Group 2 contingency occurring anywhere in Ontario.
3. On Local elements, the system *security* criteria shall be satisfied for any Appendix A Group 3 contingency occurring anywhere in Ontario.
4. BPS elements, only for the purposes of *SOLs*[2], are determined in the following manner:
    a. Start with all elements identified in accordance with *NPCC's* A-10 test performed on a set of system conditions that covers the range of anticipated operation.

[1] The *IESO* derives voltage change and stability limits, and monitors thermal limits based on ratings provided by asset owners.

[2] This section does not concern itself with other uses of BPS for *NPCC* Directory 4 applications for protections.

b. Add elements as necessary when operating conditions are more onerous than those studied in (a).

c. Remove elements that do not affect neighbouring jurisdictions. Where there is an effect, the *IESO* must obtain concurrence from affected neighbouring jurisdictions before removing the element.

5. BES elements are determined in accordance with *NERC's* BES definition.

6. Local elements are the remainder after BPS and BES elements have been determined.

The *IESO* will classify the *SOLs* derived using the methodology as noted in points 1 to 3, above, as *IROLs* based on studied impacts on neighbouring jurisdictions. Where there is an effect, IESO will obtain concurrence from affected the neighbouring *Reliability Coordinator(s)*, before removing the *IROL* designation.

The *IESO* will determine the impact of contingencies outside of the *IESO-controlled grid* to Ontario *SOL/IROLs* in the same manner as contingencies within the *IESO-controlled grid*.

A neighbouring jurisdiction will determine the criteria for assessing effects of contingencies within the *IESO-controlled grid* on their system.

4.3 System Security Criteria

4.3.1 Principles

The derivation of *SOLs* shall be done in accordance with the following system *security* criteria.

4.3.2 Thermal Rating Policy

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of thermal ratings for such equipment as communicated to the *IESO* by relevant *market participants*. When a critical adverse effect is not apparent to *market participants*, such as a backfeed arising from a recognized contingency at a remote location on the *IESO-controlled grid*, the *IESO* shall take actions to avoid exceeding thermal ratings. When a critical adverse effect is apparent to a *market participant* and he has control, such as loading of *generator* step-up or DESN transformers, the *market participant* shall take action to avoid exceeding thermal ratings.

Limited time ratings shall be utilized only if control actions are available to reduce loading to a longer time rating within the interval afforded by a limited time rating. For example, a 15-minute rating may only be utilized if control actions are available to reduce loading to a longer term rating (e.g., a 10-day rating) within 15 minutes. Post-contingency loading shall not exceed the shortest applicable limited time rating.

The scope of thermal monitoring will be established in *operating agreements* between *IESO* and *transmitters*.

4.3.3 Load Representation

Constant megavolt-amp (MVA) load models shall be used to assess a pre-contingency state.

Voltage-dependent load models may be used to assess a post-contingency state before and after tap-changer action. The default voltage-dependent load model shall be used unless a different model has been approved by the *IESO*. The default voltage dependant for active (P) and reactive (Q) load shall be defined as follows:

$P(V) = \frac{0.5*P}{P_0} \times \frac{V}{V_0} + \frac{0.5*P}{P_0} \times \left(\frac{V}{V_0}\right)^2 \qquad Q(V) = \frac{Q}{Q_0} \times \left(\frac{V}{V_0}\right)^2 \quad V_0\ P_0,\ Q_0$ are pre-contingency values

In areas where representation of load is critical, such as areas with a material amount of motor load, a detail representation of transient load behaviour should be attempted.

4.3.4 Pre-contingency Voltage Range

The *IESO-controlled grid* shall be operated in the voltage ranges shown in Table 4-1 under pre-contingency conditions and following re-preparation unless affected equipment owners have agreed to a wider range.

For transmission voltages, the values are from Chapter 4 of the *market rules*. For distribution voltages, the values are based on Canadian Standards Association (CSA) Standard 235.

Table 4-1: Pre-Contingency Voltage Limits

Nominal Bus Voltage	Transmission Stations			Transformer Station (Load Facility) Low Voltage at 44 kV, 27.6 kV, 13.8 kV
	500 kV	230 kV	115 kV	
Maximum Continuous	550 kV	250kV	127 kV*	106% of nominal
Minimum Continuous	490 kV	220 kV	113 kV	98% of nominal

* In portions of northern Ontario, the *maximum continuous* voltage for the 115kV system can be as high as 138kV.

Exceptions to maximum and minimum voltages must be documented in relevant operating instructions.

4.3.5 Post-contingency Voltage Change Limits

Transmission system voltage changes following recognized contingencies (i.e., after the contingency has been cleared) shall be limited as shown in Table 4-2, unless the equipment owner has agreed to a wider voltage change limit. Voltage declines are intended to ensure power quality, and therefore are assessed at the high voltage terminal of loads. Voltage rises are assessed at all of the buses mentioned in the table. Operating instructions must document exceptions to voltage change limits, for example voltage rise restrictions due to equipment limitations, employed in *SOL* derivation.

Table 4-2: Post-Contingency Voltage Change Limits

Transmission Bus Designation	Operating Condition	Contingency Type	Change Before Tap Changer Action	Change After Tap Changer Action
BPS	Normal	Single-element	5%	10%
		Double-element	10%	15%
	Emergency	Single-element	10%	15%
BES and Local	All	Single-element	10%	15%

4.3.6 Voltage Stability

Voltage stability for power transfers for all anticipated operating states shall be demonstrated using power-voltage (PV) analysis accordingly:

- A power transfer corresponding to Point 'A', which if increased by 10%, is less than the power at the critical point of the pre-contingency PV curve, and
- A power transfer corresponding to Point 'B', which if increased by 10%, is less than the power at the critical point of the post-contingency PV curve.

When producing a pre-contingency PV curve, manual actions such as reactive shunt switching together with transformer tap-changer action, are permitted. When producing a post-contingency PV curve, only automatic control actions (e.g., generation *automatic voltage regulation*, *RASs*, and automatic under-load tap-changes) shall be modelled.

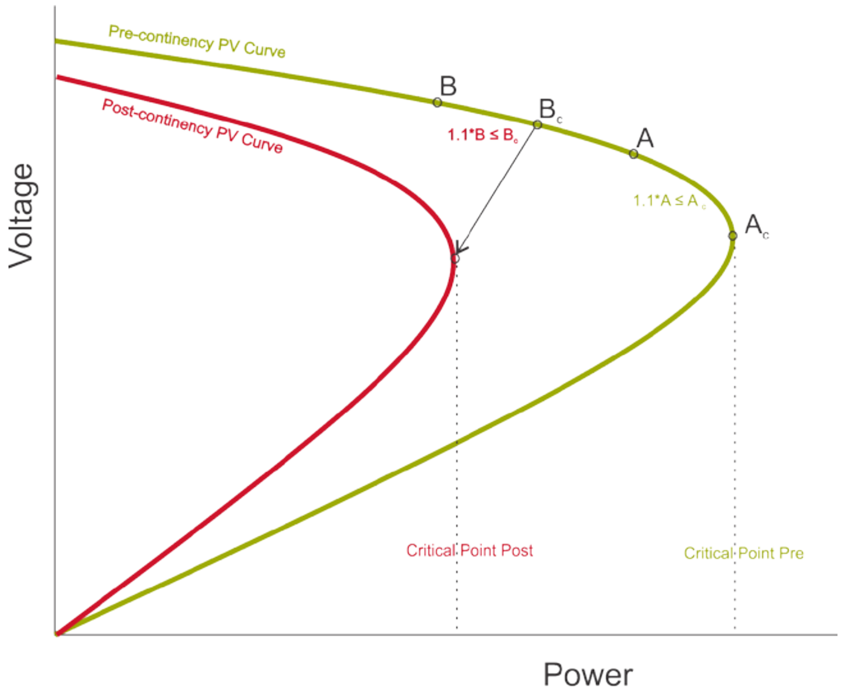


Figure 4-1: Typical PV Curves

4.3.7 Transient Stability

For acceptable transient rotor angle stability, synchronous units remaining connected to *IESO-controlled grid* shall not lose synchronism for the contingencies in Appendix A with due regard to reclosure. Transient angle stability shall be maintained if the critical parameter is increased by 10% to allow margin.

The 10% increase in the critical parameter can be simulated by generation or load changes beyond the forecast load or generation capabilities even after eliminating *station service* load. Conditions at margin shall be as realistic as reasonably achievable. The use of negative values of local load is preferable to increasing local generation beyond its maximum capability. Negative load used for margin must have a constant MVA characteristic.

Design operating times of fault detectors, auxiliary relays, trip modules, communication media, breakers, etc., may be used for calculating switching times when reliable field-measured data are not available.

4.3.8 Small Signal Stability

The required damping factors at various conditions on the *IESO-controlled grid* are tabulated in Table 4-3.

Table 4-3: Acceptable Damping Factors

System Condition	Damping Factor
Pre-contingency	> 0.03
Post-contingency: Before any automatic *response*	> 0.00
Post-contingency: After automatic *responses*, before manual system adjustments	> 0.01
Following re-preparation of the system: After system adjustments	> 0.03

For swings characterized by a single dominant mode of oscillation, the damping may be calculated directly from the oscillation envelope.

For a damping factor of 0.03, the magnitude of oscillations must be reduced to 39% of initial values within 5 periods. For a damping factor of 0.01, the magnitude of oscillations must be reduced to 39% of initial values within 15 periods. For swings not characterized by a single dominant mode, then the damping factors should be derived via a more detailed modal analysis.

4.3.9 Protection Relay Margin

Following fault clearing, or the loss of an element without a fault, the margin on all instantaneous and timed distance relays at stations that are part of the BES or BPS, including *generator* loss of excitation and out-of-step relaying, must be at least 20% and 10% respectively.

The margin on all relays at local system stations, *generator* loss of excitation and out-of-step protections on small *generating units*, or those associated with transformer backup protections, must be at least 15% on all instantaneous relays, and 0% on all timed relays having a time delay setting less than or equal to 0.4 seconds. For all relays having a time delay setting greater than 0.4 seconds, the apparent impedance may enter the timed tripping characteristic, provided that there is a margin of 50% on time. For example, the apparent impedance does not remain within the tripping characteristic for a period of time greater than one-half of the relay time delay setting.

The margin on all system relays, such as change of power relays, must be at least 10%.

4.3.10 Automatic Reclosure

The *IESO* will use automatic reclosure to more quickly restore the integrity of the *IESO-controlled grid* following contingencies that are not permanent. Experience has shown many faults on the overhead transmission circuits to be temporary. Automatic reclosure for transformer, bus, or cable protection should only be approved in exceptional circumstances, as these faults are more likely to be permanent. Auto-reclosure settings and selections shall meet the following requirements:

- A faulted circuit shall be automatically re-energized from a single preferred breaker with undervoltage supervision and a minimum time delay of five seconds. Automatic reclosure shall be initiated following damping of system oscillations. Stability-sensitive areas should have a nominal time delay of 10 seconds to initiate automatic reclosing. Areas where studies indicate that higher speed reclosure has no material adverse effects on the system *security* of the *IESO-controlled grid*, reclosing with a time delay of less than five seconds is permitted.

- The breaker chosen for the re-energization of the circuit shall be the one that would result in the least disruption in the event of a breaker failure upon an unsuccessful reclosure. Experience has shown there is a higher-than-average risk of breaker failure in an open-close-open sequence. The re-energizing breaker shall be at a terminal remote from steam turbine units. On a reasonable effort basis, re-energizing should be initiated at a breaker at a terminal remote from generating units.
- The remaining breakers shall automatically reclose with synchrocheck supervision. Where there is no electrically close generating station, voltage presence supervision with a nominal time delay of 0.5 seconds may be used.
- Automatic reclosing must NOT result in a sudden power change exceeding 0.5 per unit of its MVA rating on steam turbine generating units rated greater than 10 MVA. *Market participant* agreement shall be obtained prior to allowing a higher value of sudden power change.
- Automatic reclosing time delay settings for adjacent transmission circuits on common towers are selected to mitigate the risk of reclosing onto two faulted circuits at the same time.
- Automatic reclosure shall NOT be used to re-synchronize a generating unit that has separated from the *transmission system*.
- On those circuits where only high speed (i.e., less than one second) unsupervised automatic reclosure is available, it should normally be blocked.

SOLs shall be derived such that the system must successfully withstand an unsuccessful automatic reclosure (i.e., an open-close-open sequence) operation.

4.3.11 Manual Energization

The *IESO-controlled grid* must be able to withstand manual energization of a faulted element without prior readjustment of generation levels, unless specific operating instructions to the contrary are provided.

Following an unsuccessful automatic reclosure, or an *outage*, a circuit will normally be manually re-energized from the preferred breaker used for automatic reclosure.

4.4 Frequency Regulation

Generators are required to be able to operate within the range of frequencies specified in *MR* Ch. 4, Appendix 4.2: General Facility Requirements. This appendix also specifies the required governor settings for speed/frequency regulation.

Market Manual 7.1: IESO-Controlled Grid Operating Procedures explains how generators are required to operate during abnormal system frequencies.

4.4.1 Automatic Under Frequency Load Shedding

The *IESO* shall administer an automatic under-frequency load shedding (UFLS) program to stabilize frequency. This program shall take into consideration the manner in which the *IESO-controlled grid* is likely to separate in the event of a *system disturbance*, compensation for early generation tripping, and *planned outages* with Planned, Opportunity, or Information Priority Code to UFLS equipment.

IESO requirements for the UFLS program are contained in MM 7.1. Priority customer loads (refer to *Market Manual* 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup *generators*, and electrically driven gas compressors should be considered by *distributors* and *connected wholesale customers* when satisfying UFLS program requirements.

4.5 Restoration of System Security

4.5.1 Principles

The *IESO* shall use all available means to re-prepare the system to satisfy *SOLs* corresponding to emergency condition operating limits as soon as possible, but within 30 minutes following any contingency. The 30-minute period starts following the occurrence of the contingency.

The consequences of control actions to return to a studied operating state must be both foreseen and acceptable. The intentional loss of a major portion of the system, or the intentional separation of a major portion of the system, are unacceptable consequences.

4.5.2 Policies

The minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load*, to observe the emergency condition operating limits in the pre-contingency phase, and to restore system operation to the emergency condition operating limits in the post-contingency phase within 30 minutes. All necessary steps are to be taken to shorten the duration of an *emergency operating state*.

The *IESO* must have plans to re-prepare system *security* within 30 minutes following the occurrence of respected contingencies.

Re-preparation plans shall not utilize control actions that increase *non-dispatchable load* shedding until resources have been committed in accordance with the Area Reserve criteria in Section 3.4.

The *IESO* publishes and maintains a power system restoration plan for Ontario in the event of a complete or partial blackout of the *IESO-controlled grid* (refer to *Market Manual* 7.8: Ontario Power System Restoration Plan).

– End of Section –

Appendix A: Recognized Contingencies

The types of contingencies that must be respected on elements[3] that form the BPS and BES are, at a minimum, specified by *NPCC* and *NERC* respectively. The types of contingencies that must be respected on the remaining local elements are specified by the *IESO*. The consequences of Group 1, Group 2, and Group 3 contingencies must be considered on BPS, BES, and local elements respectively.

Single-element contingencies result in the clearing of a single protection zone, with the exception of inadvertent breaker opening contingencies. A single protection zone may comprise more than one element. To restore system *security*, it can be assumed that only one element was faulted, and the other elements comprised within a single protection zone can return to service. The timing of the return to service depends upon the particulars associated with the fault location. System *security* must be restored considering all elements that cannot be returned to service within 30 minutes.

When the *IESO-controlled grid* is in a *high risk operating state*, the *IESO* may operate the system to withstand contingencies more severe than those specified below for a *normal operating state*.

A.1 Group 1 – Contingencies

A.1.1 Normal Operating State

When the *IESO-controlled grid* is in a *normal operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) Simultaneous permanent phase-to-ground faults on the same or different phases of each of two adjacent transmission circuits on a multiple transmission circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition is an acceptable risk and is excluded.

(iii) A permanent phase-to-ground fault on any element with delayed fault clearing.

(iv) Loss of any element without a fault.

(v) A permanent phase-to-ground fault on a circuit breaker, with normal fault clearing.

(vi) Simultaneous permanent loss of both poles of a direct current bipolar *facility*.

(vii) The failure of a circuit breaker associated with a *RAS* to operate when required following the loss of any element without a fault, or a permanent phase-to-ground fault (with normal fault clearing) on any element.

A.1.2 Emergency Operating State

When the *IESO-controlled grid* is in an *emergency operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) Loss of any element without a fault.

[3] An element is defined as *generator*, transmission circuit, transformer, breaker, shunt device, or bus section.

A.2 Group 2 – Contingencies

A.2.1 Normal Operating State

When the *IESO-controlled grid* is in a *normal operating state*, the Group 2 contingencies are:

(i) A permanent three-phase or single-phase-to-ground fault with normal clearing on any element.

(ii) Loss of any element without a fault.

(iii) Single pole block with normal clearing in a monopolar or bipolar HVdc system.

A.2.2 Emergency Operating State

When the *IESO-controlled grid* is in an *emergency operating state*, the Group 2 contingencies are:

(i) A permanent three-phase fault on any element.

(ii) Loss of any element without a fault.

A.3 Group 3 – Contingencies

When the *IESO-controlled grid* is in a *normal* or *emergency operating state*, the Group 3 contingencies are:

(i) A-phase-to-phase-to-ground fault with normal clearing on any element.

(ii) Loss of an element without a fault.

– End of Section –

.

Appendix B: Load and Generation Rejection and Generation Runback Selection Criteria

Load Rejection (L/R) Selections

a. L/R should be selected to satisfy the following in order of priority:

  (i) **System security.** L/R selections must satisfy system *security* requirements for specific station and/or a specific megawatt requirement (to within an acceptable deadband). L/R must be selected such that the resulting transmission conditions do not prevent L/R actions to alleviate the system *security* concerns. L/R selections in the vicinity of a natural or man-made disaster must not hamper *emergency* measures.

  (ii) **Sensitivity.** Priority customer loads (refer to *Market Manual* 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup *generators*, and electrically driven gas compressors should be avoided when determining what load to shed.

  (iii) **Minimize Number of Stations.** The number of stations selected for rejection should be minimized.

  (iv) **Trip History.** L/R selections should attempt to equalize the number of L/R operations for each station over the long term and minimize the exposure of any station to two successive L/R operations.

  (v) **Area Fairness.** Where L/R may be available for selection in more than one area, the stations selected for L/R should be distributed among each participating area. This distribution should be in approximate proportion to the percentage of the total load supplied by all areas involved in the scheme.

b. Opening bus tie breakers to increase *non-dispatchable load* lost by configuration shall be considered as L/R.

c. L/R selections will be minimized where affected *IESO-controlled grid delivery points* are not within *reliability* performance standards.

d. L/R selected to relieve post-contingency thermal overloading shall be:

  (i) Sufficient to comply with the thermal rating policy.

  (ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate "limited" time.

Generation Rejection Selections

a. Generation Rejection (G/R) should be selected to satisfy the following in order of priority:

  (i) **System security.** G/R requirements must satisfy system *security* requirements for specific unit selections and/or specific megawatt requirement (to within an acceptable deadband).

  (ii) **Minimize Number of Units.** The number of units selected and total amount selected for G/R should be minimized within the constraints imposed by plant and system operating conditions.

(iii) **Trip History.** Selections should attempt to equalize the number of unit trips based on history.

b. G/R selections for single element *contingency events* shall be minimized.

c. G/R selected to relieve post-contingency thermal overloading shall be:

(i) Sufficient to comply with the thermal rating policy.

(ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate “limited” time.

d. G/R selections should avoid manual corrective measures following a G/R operation,

e. G/R selections should be made on a reasonable effort basis to address *market participant facility* concerns such as the:

(i) Maximum number of units selected within a single *control center*,

(ii) Minimum number of unselected generating units, and

(iii) Unavailability or preferences of specific units for G/R selection.

Generation Runback Selections

All policies in place for G/R apply equally to Generation Runback.

– End of Section –

Appendix C: RAS Restrictions during High Risk Operating State

<table>
<tr><th colspan="2">Contingency Type</th><th>High Risk Operating State Due to Adverse Weather within the Weather Advisory Area
(refer to notes A, B, C and D)</th><th>High Risk Operating State Due to Conditions not within the Weather Advisory Area
(refer to notes A, B and C)</th></tr>
<tr><td rowspan="2">500 kV
230 kV
115 kV</td><td>Recognized Double Element</td><td>No restrictions to G/R or L/R</td><td rowspan="2">The primary concern is adverse effects of a false RAS operation. The following restrictions therefore apply:
• G/R or runback is permissible provided its use is minimized.
• L/R is permissible, provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
<tr><td>Recognized Single Element</td><td>G/R or runback is permissible, provided:
• Arming is limited to outage periods or short-duration periods, or
• Its magnitude is reduced during adverse weather periods
G/R is permissible, provided the only other alternative is to remove the unit from service, or the unit would be automatically removed from service as a result of the initiating contingency.
L/R is permissible provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
</table>

(A) A *RAS* must NOT be utilized if a fail-to-trip condition is suspected.

(B) A *RAS* may be selectively used to provide additional *system security* beyond normal criteria, provided the restrictions in this table are observed.

(C) The restrictions in this table do not apply to *RAS* selections for extreme contingencies.

(D) The Weather Advisory Area is within 50 km of the circuits for which the *RAS* is selected.

– End of Section –

References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_PRO_0016	Market Manual 1.2: Facility Registration, Maintenance and De-registration
MDP_PRO_0024	Market Manual 2.8: Reliability Assessments Information Requirements
IMP_MAN_0012	Market Manual 7.0: Systems Operations Overview
IMP_PRO_0033	Market Manual 7.2: Near-Term Assessments and Reports
IMP_PRO_0035	Market Manual 7.3: Outage Management
IMP_GOT_0002	Market Manual 7.6: Glossary of Standard Operating Terms
IMO_PLAN_0001	Market Manual 7.8: Ontario Power System Restoration Plan
IMO_PLAN_0002	Market Manual 7.10: Ontario Electricity Emergency Plan
IESO_PRO_0874	Market Manual 11.2: Ontario Reliability Compliance Program

– End of Document –

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 10

NextBridge-10

Reference: The IESO's June 29, 2018 Report at 2, lines 9 through 3, line 11.

INTERROGATORY

Explain in detail under what system conditions would the identified options be needed to maintain system reliability.

RESPONSE

There are a number of system conditions which increase the likelihood that the identified options would be used. These conditions include high demand, low imports from neighbouring jurisdictions, reduced water availability at generators, generator outages and transmission outages.

No single condition can be identified which on its own would necessitate use of the identified options. A combination of factors would ordinarily necessitate use of the identified options.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 11

NextBridge-11

Reference: The IESO's June 29, 2018 Report at 3, lines12-18.

INTERROGATORY

Provide the criteria, if any, the IESO used to determine that its estimate of capacity cost was "reasonable."

RESPONSE

As stated in the IESO's Addendum to the 2017 Updated Needs Assessment, the cost of capacity is uncertain. In cases where the cost of capacity is uncertain, a usual approach is to estimate costs based on the levelized lifetime cost of new build capacity.

Typically, the IESO considers the following criteria in estimating potential capacity cost: (1) previous experience acquiring capacity, (2) power plant cost modelling, and (3) relevant benchmarks adjusted for time and location.

For criterion (1), capacity costs for generators in the northwest vary widely; however, the capacity cost estimate used is within the range of historical capacity costs in the region. For criterion (2), the estimate of capacity cost used is from third-party cost estimates based on modelling the cost of new generating capacity in northern Ontario. Criterion (3), adjusted benchmarks, was not applied because the IESO believed the unique geographical and other features of the Northwest made such benchmarks unreliable. In addition to the above criteria, sensitivity analysis was performed to examine the range of potential outcomes and confirm reasonableness.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 12

NextBridge-12

Reference: The IESO's June 29, 2018 Report at 3, lines12-18.

INTERROGATORY

a) Confirm that a cost was not estimated for the outage of the existing East-West Tie line for the 15 day period that Hydro One under the Lake Superior Link project estimates it would take to construct its new quad circuit towers in Pukaskwa National Park. If so confirmed, provide an estimate of the capacity and energy costs associated with a 15 day and a 21 day outage of the existing East West Tie line, and add those costs to Table 2 and reproduce Table 2. If not confirmed, explain in detail your response.

b) Explain in detail whether the rejection of 150 MW of load for only 8 hours planning criteria is consistent with allowing a planned outage of the existing East-West Tie line for 15 or more days to construct the quad circuit towers.

RESPONSE

a) A cost was not estimated for the outage of the existing East-West Tie line for the 15 day period that Hydro One, under the Lake Superior Link project, estimates it would take to construct its new quad towers in Pukaskwa National Park. The IESO does not provide or calculate such costs as outage assessments are based on reliability.

b) Please see the response to NextBridge Interrogatory 6a). The IESO would not approve an outage if it would result in negative reliability impacts. The outage would be scheduled when there is sufficient supply available to meet the demand in the Northwest. When scheduling this outage, the IESO would also consider availability of energy in neighbouring jurisdictions and other planned outages in the region.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 13

NextBridge-13

Reference: The IESO's June 29, 2018 Report at 3, lines12-18.

INTERROGATORY

a) Confirm that the societal (customer) cost associated with the rejection of 150 MWs of load for 8 hours was not estimated and included in the Report.

b) Provide an estimate of the societal (customer) cost associated with the rejection of 150 MWs of load for 8 hours and add that cost to Table 2 and reproduce Table 2.

RESPONSE

a) Confirmed. The societal (customer) costs associated with the rejection of 150 MWs of load for 8 hours was not estimated and included in the report.

b) The IESO does not estimate the societal cost associated with load rejection.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 14

NextBridge-14

Reference: The IESO's June 29, 2018 Report at 4, lines 1-4.

INTERROGATORY

a) How does the IESO compare the risk of acquiring interim measures pre-2022 to 2022 and beyond?

   i. Please provide an analysis on how the risk was determined to be acceptable until the end of 2022.

RESPONSE

a) and i) Please refer to pages 3-4 of the IESO's Addendum to the 2017 Updated Needs Assessment which outlines the IESO's rationale around the increased risk post-2022.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 15

NextBridge-15

Reference: The IESO's June 29, 2018 Report at 4, lines 10-12.

INTERROGATORY

What lead time does the IESO need to implement each of its interim options?

RESPONSE

The estimated lead time required for each interim option is outlined below. Please note that the lead times are assumed to commence from when the decision is made to pursue a given option or sub-option.

- **Firm Imports** – The IESO would likely require approximately two years to secure firm imports, including 6–12 months to negotiate an operating agreement with one or both of MISO and Manitoba Hydro. Securing one or more firm capacity agreements with external resources would likely be accomplished through a competitive procurement process or through bilateral negotiations.
- **Demand Response** – DR resources are typically secured through the annual DR Auction approximately 6 months in advance of the start of the summer commitment season and 12 months in advance of the winter commitment season. The lead time would depend on when the decision is made to secure new demand response relative to when the next demand response auction would be run (the demand response pre-auction report is published annually in late September for the auction that is run in December; September 20 and December 5, 2018 for the 2019 auction). A stand-alone targeted demand response procurement for the northwest that leverages the current DR Auction could also be considered, but this would require modifications to the Auction Engine tool and may also require Market Rule or Market Manual changes that could make this option less expedient. The IESO estimates that this option could require up to 12 months to complete.
- **Re-acquiring Off-Contract Facilities** – Based on past experience, the IESO would likely require up to 18 months to negotiate new bilateral agreements with un-contracted facilities. If a competitive procurement approach were to be pursued, the process would likely require up to 14 months to complete. Any time required for permitting, construction and commissioning activities would be in addition to these timelines.

The timelines for the foregoing options could be further extended if any of the options require a Ministerial Directive.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 16

NextBridge-16

Reference: The IESO's June 29, 2018 Report at 4, Table 1.

INTERROGATORY

a) Explain in detail how Project Cost and Projected Cost Range were calculated including the price(s) and number of hours estimated for the capacity purchases.

b) Explain the significance, if any, of the inclusion of the Allowable Load Rejection Column.

   i. If the Allowable Load Rejection column was eliminated, would that change the Project Cost column estimates? If yes, please reproduce Tables 1 and 2 with the Allowable Load Rejection column eliminated and the Projected Cost column recalculated.

RESPONSE

a) The "Projected Cost" column in Table 1 is based on the estimated lifetime levelized cost of new local generating capacity in Northern Ontario, which is $180/kW-year. The high end of the "Projected Cost Range" is $225/kW-year, which is 25% higher than $180/kW-year. The low end of the "Projected Cost Range" is $76/kW-year (rounded to $80/kW-year in the report), which was the average annual clearing price of the IESO's 2017 demand response auction. Costs were calculated based on a commitment period spanning the entire year.

b) The allowable load rejection column identifies the amount of allowable load rejection which is assumed in order to determine the remaining incremental capacity need. If the allowable load rejection column was eliminated, the incremental requirement column would be the same as the requirement column. As a result, the projected cost and projected cost range columns would increase proportionally.

   Since IESO is authorized to rely upon and utilize load rejection in this instance, it is not necessary to reproduce the table ignoring the impact of load rejection as an interim measure.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 17

NextBridge-17

Reference: The IESO's June 29, 2018 Report at 4, lines 13-15.

INTERROGATORY

a) Confirm that the capacity cost estimate sensitivity did not take into account the stated concern that acquiring the interim options may come at a higher cost. Identify the highest capacity cost that could be required by one of the interim options.

b) Incorporate that highest possible cost into Table 2 calculations and reproduce Table 2.

RESPONSE

a) and b) The projected cost range takes into account the highest capacity cost that the IESO currently believes, based on available information and its experience, would be required to be incurred to secure any one of the interim options.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 18

NextBridge-18

Reference: The IESO's June 29, 2018 Report at 4, line 25 through 5, line 3.

INTERROGATORY

a) Identify the referred to Northern Ontario interfaces subject to congestion.

b) Please provide the number of hours per year that it is estimated that low-cost hydro power will be unavailable in 2021 and 2022.

RESPONSE

a) The following northern Ontario transmission interfaces are subject to eastbound congestion: East-West Tie Flow East, Mississagi Flow East, and the Flow South.

b) It is estimated that low-cost hydro power will be unavailable for 242 hours in 2021 and 252 hours in 2022 assuming an East-West Tie Flow East operating limit of 235 MW. The 235 MW east-bound operating limit is reflective of the historical 50%-of-time hourly operating limit (since the operating limit changes based on real-time system conditions).

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 19

NextBridge-19

Reference: The IESO's June 29, 2018 Report At 4, line 25 through 5, line 3.

INTERROGATORY

Provide in detail how the energy replacement cost was calculated, including the estimated price and the number of hours the replacement energy was required to be purchased.

RESPONSE

The energy cost was calculated based on two separate runs of an economic energy dispatch model. Simulated energy production costs from a scenario with the East-West Tie Expansion in service and median water conditions were compared to energy production costs without the East-West Tie Expansion in service and also under median water conditions.

The difference between the total system energy production costs in the two runs represents the additional system efficiency and cost savings associated with having the East-West Tie Expansion in service.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 20

NextBridge-20

Reference: The IESO's June 29, 2018 Report at 5, lines 4-7.

INTERROGATORY

Confirm that no probabilistic scenarios were modeled with higher costs than $.5 million (2017$) per year. If not confirmed, provide the probabilistic scenarios, including an estimate for the high range of energy replacement costs and include that cost in Table 2 and reproduce Table 2. If confirmed, calculate a high range of energy replacement costs and include that cost in Table 2 and reproduce Table 2.

RESPONSE

The energy studies conducted as part of the IESO 2017 Needs Update Report, which were used to inform the foregone energy cost savings in the IESO's Addendum to the 2017 Updated Needs Assessment, do not include probabilistic scenarios. These studies simulated the economic dispatach of the system based on a set of assumptions of demand, generation characteristics and transmission limitations.

The IESO did model a high water scenario in addition to the median water scenario in the energy dispatch model's reference case. The foregone energy cost savings, considering a high water scenario, has been added to the values in Table 2.

Revised Table 2 Summary of Potential Cost of Delay to In-Service Date (2020-2024) with Energy Costs Updated for High Water Conditions

Year	Potential Capacity Cost (2017$ millions)	Energy Cost (2017$ millions)		Foregone Loss Savings (2017$ millions)	Total Potential Cost of Delay (2017$ millions)	
		Median Water	High Water		Median Water	High Water
2020	$16	$0.5	$1.9	$0.7	$17	$19
2021	$18	$0.5	$1.9	$0.7	$19	$21
2022	$22	$0.5	$1.9	$0.7	$23	$25
2023	$38	$0.6	$3.8	$0.7	$39	$42
2024	$44	$0.6	$4.2	$0.7	$45	$49

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 21

NextBridge-21

Reference: The IESO's June 29, 2018 Report at 5, Table 2.

INTERROGATORY

Confirm that the appropriate reading of Table 2 is if the new East-West Tie Line is in service by the end of 2020, then approximately $19 million dollars would be saved in 2021, and another $23 million in 2022 for a total savings of $42 million dollars in savings for those two years. If not confirmed, please explain your response in detail.

RESPONSE

Confirmed.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 22

NextBridge-22

Reference: Hydro One March 29, 2018 Lake Superior Link Additional Evidence, page 6.

Preamble: For the long-term operation of the lines, Hydro One states that installation of the four-circuit line in the Park will not have a more adverse impact on overall reliability of the power system than the other alternative of having two separate double-circuit EWT lines.

INTERROGATORY

Does IESO agree with this statement? If not, why not?

RESPONSE

Hydro One's proposed four-circuit line in the Park complies with NERC, NPCC and ORTAC planning standards and as long as Hydro One meets the conditions set out in the System Impact Assessment, Hydro One's proposed Lake Superior Link project will not have an adverse impact to reliability. From an operating perspective, based on the IESO's limited experience with four circuit towers in the Northwest, it is difficult to assess whether, and to what extent, it may be less reliable than the two separate double-circuit line alternative.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 23

NextBridge-23

Reference: The IESO's June 29, 2018 Report.

INTERROGATORY

a) Confirm that the Report also shows that there are additional potential costs associated with the operation of Hydro One's quad transmission tower design through Pukaskwa National Park, because the loss of all four circuits would require the implementation of the same rejection of load and interim options as set forth in the Report. If not confirmed, explain you response in detail.

b) Reproduce Table 2 and provide an estimate of the additional costs associated with replacement capacity and energy costs assuming the Hydro One quad transmission tower design was constructed and operational at the end of 2022, and the Hydro One quad tower design had a 1, 5, and 10 day outage during a typical peak period in the years 2023 and in 2024.

RESPONSE

a) Not confirmed. Planning standards do not require the IESO to plan for the loss of all four circuits on a common tower and, therefore, the IESO would not arrange for additional supply capacity in the northwest to address this contingency. For clarity, according to the applicable planning standards, the four circuit tower alternative and the two separate double circuit tower alternative satisfy the capacity need in the northwest.

b) The cost categories in Table 2 would not apply to the outage event(s) described.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 24

NextBridge-24

Reference: The IESO's June 29, 2018 Report.

INTERROGATORY

a) Confirm that, all other things being equal, from a reliability perspective and ability to serve load without interruption, the IESO would rather see two parallel (existing and new) East West Tie lines in operation versus the Lake Superior Link proposal using approximately 90 quad circuit transmission towers. If not confirmed, explain your response in detail.

b) Assuming the Lake Superior Link is in-service by the end of 2022, what is the maximum amount of hours or days that the Lake Superior Link quad circuits could be out of service during a typical system peak period without jeopardizing system reliability for (i) the years studied in the Report and (ii) when East-West Tie transfer capability is increased to 650 MW?

c) Assuming the Lake Superior Link is in-service by the end of 2021, what is the maximum amount of hours or days that the Lake Superior Link quad circuits could be out of service during a typical system peak period without incurring a loss of load for (i) the years studied in the Report and (ii) when East-West Tie transfer capability is increased to 650 MW.

d) Explain in detail how the load that relies on the Lake Superior Link project would be fed if all four circuits of the Lake Superior Link are out of service during a typical peak period.

e) Explain in detail whether there is a different probability or level of risk for loss of load if only two circuits on the Lake Superior Link are out of service versus all four.

RESPONSE

a) Please see the response to NextBridge Interrogatory 22.

b) This analysis was not completed by the IESO as planning standards do not require the IESO to plan for the loss of all four circuits during peak conditions.

c) and d) Please see the response to b) above.

e) With two circuits out of service, the transfer capability of the East-West Tie interface is higher than with four circuits out of service. Therefore, it is reasonable to expect that the risk of load loss is greater in the latter case. Furthermore, since the system is planned to be adequate while respecting the loss of a double circuit line, load should not be lost for an extended period of time if only two circuits are out of service. If all circuits are out of service, load may be at risk depending on generation levels, load levels and available imports into the area.

Page Intentionally Blank

NEXTBRIDGE INTERROGATORY 25

NextBridge-25

Reference: The IESO's June 29, 2018 Report.

INTERROGATORY

Has the IESO conducted any additional analyses or come into additional information that would change the results of the Report? If yes, please update the sections of the Report that are impacted by the additional analyses or information.

RESPONSE

No, the IESO has not received additional information or conducted any additional analysis that would change the results of the report.

Page Intentionally Blank

PWU INTERROGATORY 1

PWU-1

INTERROGATORY

Ref 1: Addendum to 2017 Updated Assessment for the Need for the East-West Tie Expansion, Pages 2-3

- The 2018 demand response auction cleared 30 MW of demand response in the summer and winter in the Northwest for approximately $80/kW-year. However, the product's availability limits its contribution to meeting the capacity need in the Northwest and the extent to which additional demand response can be acquired in the Northwest on a cost-effective basis is unknown.
- The cost of firm import capability from Manitoba is uncertain; it would not be known until the time of negotiation and the price could be increased by the short commitment period and reduced competition due to the small size of the Northwest market. Currently, the firm import capability from Manitoba is also limited to between 150 – 200 MW. To inform a decision with respect to acquiring firm imports, the cost of a firm capacity import from Manitoba would be compared to the cost of acquiring new local generating capacity. The lifetime levelized cost of new local generating capacity in Northern Ontario is approximately $180/kW-year.[1]

Ref 2: Addendum to 2017 Updated Assessment for the Need for the East-West Tie Expansion, Page 4

Table 1 Projected Cost of the Incremental Capacity Requirements (2020-2024)

Year	Requirement (MW)	Allowable Load Rejection (MW)	Incremental Requirement (MW)	Projected Cost (2017$ millions)	Projected Cost Range (2017$ millions)
2020	239	150	89	$16	$7 to 20
2021	251	150	101	$18	$8 to 23
2022	272	150	122	$22	$9 to 27
2023	360	150	210	$38	$16 to 47
2024	394	150	244	$44	$19 to 55

a) Please provide any analysis or calculations used to determine the $180/kW-year assumption for new local generating capacity.

b) Please confirm that the cost of new local generation capacity ($180/kW-year) is the assumed cost for all incremental capacity requirement used in this analysis.

c) If a 2018 demand response auction cleared 30MW at a cost of $80/kW-year, why is it

[1] The $180/kW-year reflects economies of scale associated with addressing a smaller capacity need in the interim as some of the need is managed through load rejection.

implicitly assumed that no additional demand response can be cleared for less than $180/kW-year?

d) Likewise, why is it implicitly assumed that additional capacity from Manitoba cannot be acquired for less than $180/kW-year?

e) What is the current cost of capacity from Manitoba?

f) Why does the IESO assume a consistent lifetime levelized cost of new local generation capacity of $180/kW-year for the years 2020 to 2024?

RESPONSE

a) The estimate of capacity cost used is based on a third-party cost estimate which modelled the cost of new generating capacity in northern Ontario. The levelized capacity cost of $180/kW-year is the estimated levelized payment that would be needed for a new simple-cycle combustion turbine to recover capital costs and estimated fixed costs over its lifetime. Assumptions (in $2017 CAD) relating to this include:

1. Overnight capital cost of $1,900/kW,
2. Sustaining capital of $380/kW in year 21,
3. Two years of construction, 30 year lifetime,
4. Weighted Average Cost of Capital of 7%, and
5. Estimated fixed operating and maintenance and gas delivery and management costs of $43/kW-year.

The costs also reflect the impacts of inflation and foreign exchange rate exposure at the time of the analysis.

b) Confirmed, the cost estimate used for all rows of the "Projected Cost" column in Table 1 of the IESO's Addendum to the 2017 Updated Needs Assessment is $180/kW-year. The IESO's analysis included a sensitivity range ("Project Cost Range") to reflect uncertainty in the cost of interim capacity.

c) It was not implicitly assumed that no additional demand response can be cleared for less than $180/kW-year. The low end of the sensitivity range is the average annual clearing price of the IESO's 2017 demand response auction and is reflected in the Project Cost Range column of Table 1.

d) It was not implicitly assumed that additional capacity from Manitoba cannot be acquired for less than $180/kW-year. Please refer to the response to PWU Interrogatory 1e below.

e) The cost of a firm capacity import from Manitoba is uncertain.The IESO does not currently purchase firm capacity from Manitoba and the price for firm capacity would not be known until the time of a procurement

f) Please see the response to Nextbridge Interrogatory 11.

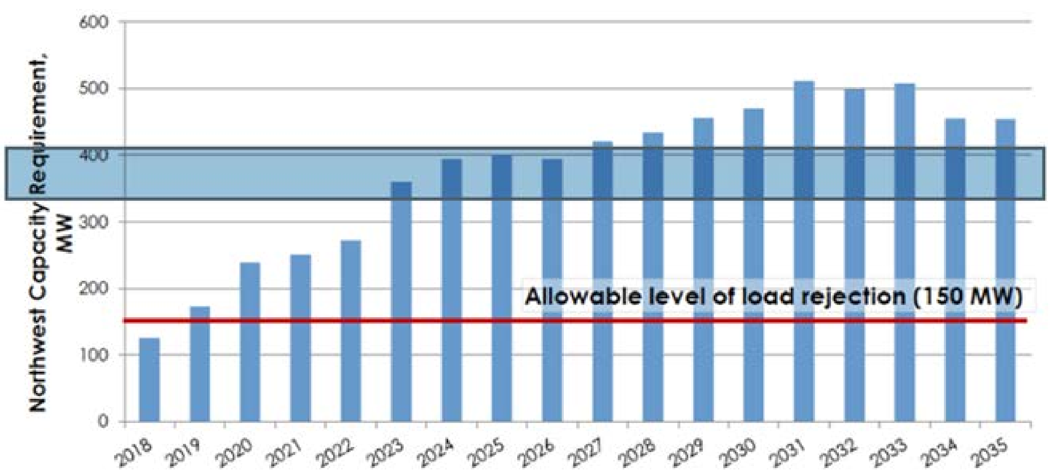
PWU INTERROGATORY 2

PWU-2

INTERROGATORY

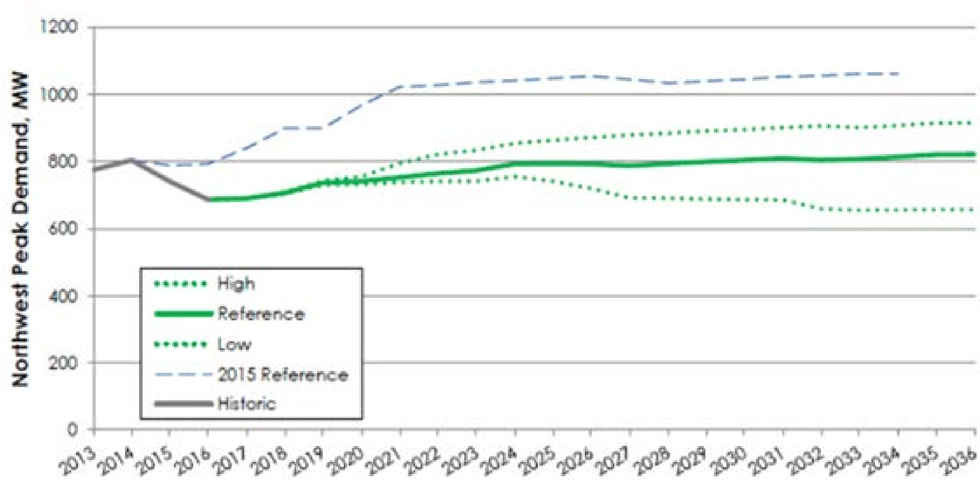
Ref 1: Addendum to 2017 Updated Assessment for the Need for the East-West Tie Expansion, Page 2

Figure 1 Expected Incremental Northwest Capacity Requirement under Reference Demand (2017 Update Report)



Ref 2: Updated Assessment of the Need for the East-West Tie Expansion (December 1, 2017), Page 11

Figure 2. Northwest Net Peak Demand Outlooks



a) Has the IESO revised its peak demand forecast for the Northwest region since the last assessment update? If so, please provide an update to Figure 1.

b) Forecast peak demand has declined materially since the 2015 Reference. Please provide evidence this trend has reversed since 2016, as per the Reference line in Figure 2.

<u>RESPONSE</u>

a) No, the IESO has not revised its forecast for the Northwest region since the last assessment update from December 1, 2017.

b) Table 1 shows historic peak demand in the Northwest from 2015 to 2017 with an initial assessment for 2018.

Table 1 Historic peak demand for the Northwest (2015-2018)

Year	2015	2016	2017	2018 (preliminary)
Northwest Historic Peak Demand (MW)	741	687	699	728

SEC INTERROGATORY 1

SEC-IESO-1

INTERROGATORY

[p.4] The addendum states that the "IESO does not support allowing the E-W Tie Expansion to be delayed beyond the end of 2022 as the increased risk to system reliability and the associated costs uncertainties are unacceptable."

a) Please explain in further detailed why the system reliability risks after 2022 reach a level in which the IESO deems them unacceptable.

b) At the beginning of which month in 2023 does the IESO believe that risk becomes unacceptable?

RESPONSE

a) Please see the response to NextBridge Interrogatory 14 a).

b) The IESO did not assess the month in which the risk becomes unacceptable.

Page Intentionally Blank

SEC INTERROGATORY 2

SEC-IESO-2

INTERROGATORY

[p.5] In Table 2 the IESO has provided a summary of potential costs of delay to the in-service date for each year between 2020 and 2024. Please provide a breakdown of the potential costs of delay on a monthly basis, beginning in December 2020 (forecast Nextbridge in-service date) until the end of 2024.

RESPONSE

The IESO's assessment was not carried out on a monthly basis and the costs were not calculated on a monthly basis.

Page Intentionally Blank

SEC INTERROGATORY 3

SEC-IESO-3

INTERROGATORY

Has the IESO conducted any analysis, either formal or informal, regarding the differences of total system cost the Nextbridge and Hydro One projects based on their differing forecast in-service dates and construction budgets. If so, please provide a copy.

RESPONSE

No, the IESO has not conducted such a cost analysis.

Page Intentionally Blank