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

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Issue	Reason for Issue	Date
1.0	First release	June 4, 2003
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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

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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:

<u>Permissible Control Actions Following Contingency</u>

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.

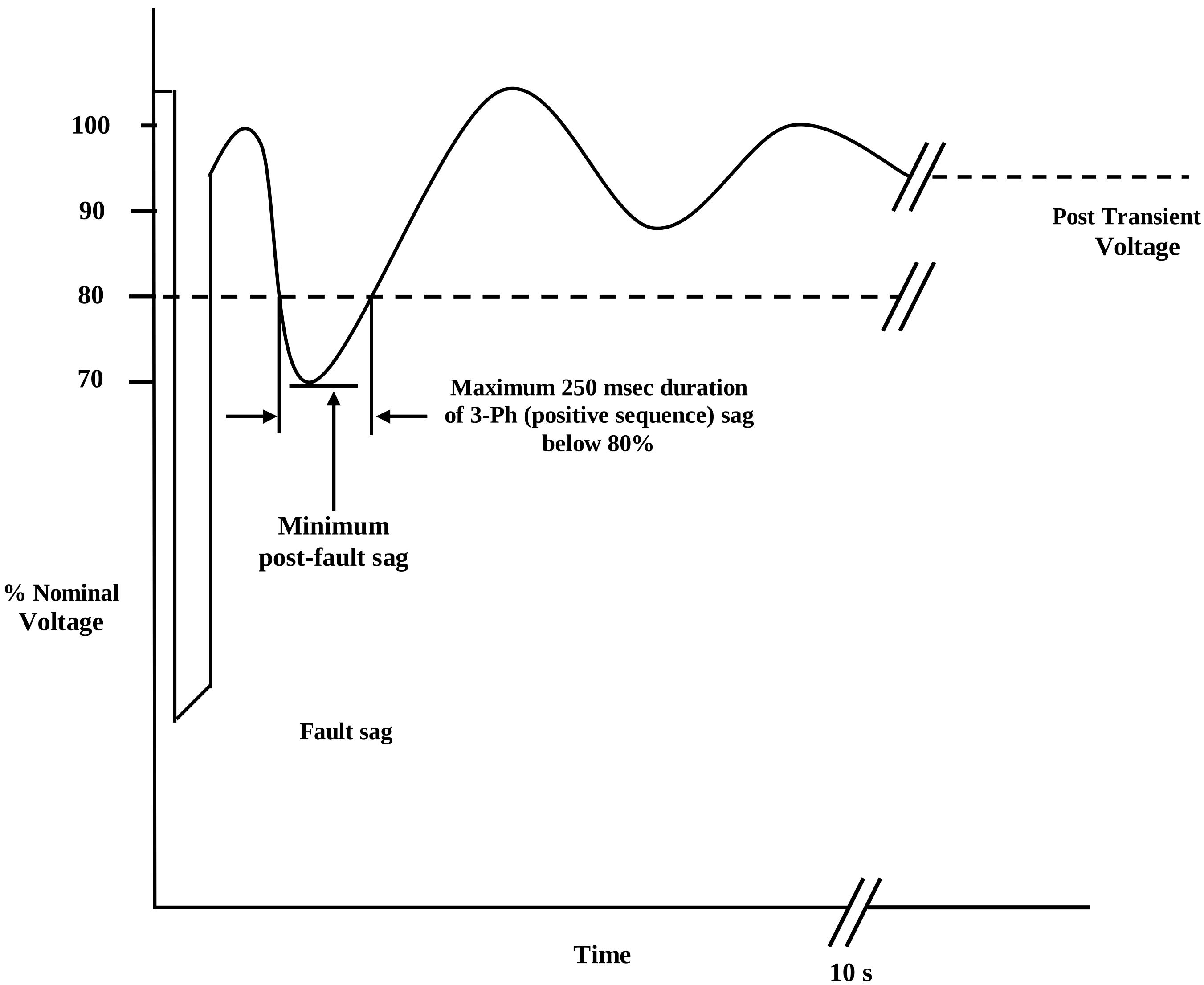
For transient voltage performance, studies should be done with a load model representative of the actual load. If that information is not available, the standard voltage dependent load model of P=50, 50, Q=0, 100 is to be used (see section 2.4 Load Forecasts and Load Modelling).

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.

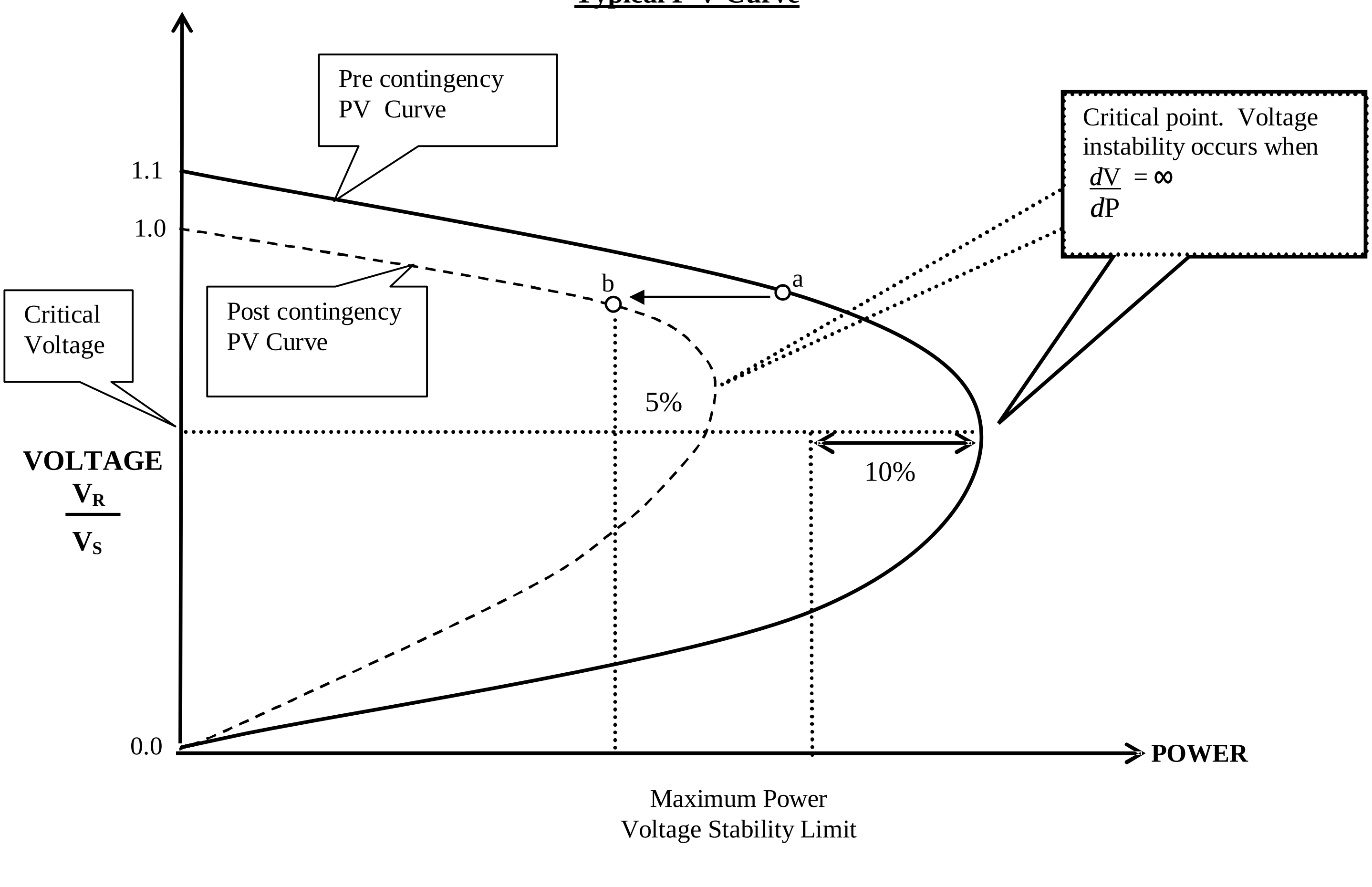
Power flow programs can be used to generate a P-V curve. In certain situations it may be desirable to manually generate a P-V curve to take into account specific remedies available.

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



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.

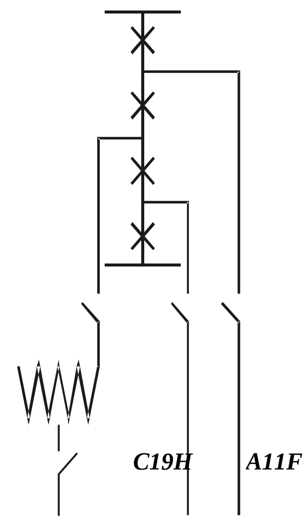
B.3 General Requirement's For Station Layouts

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

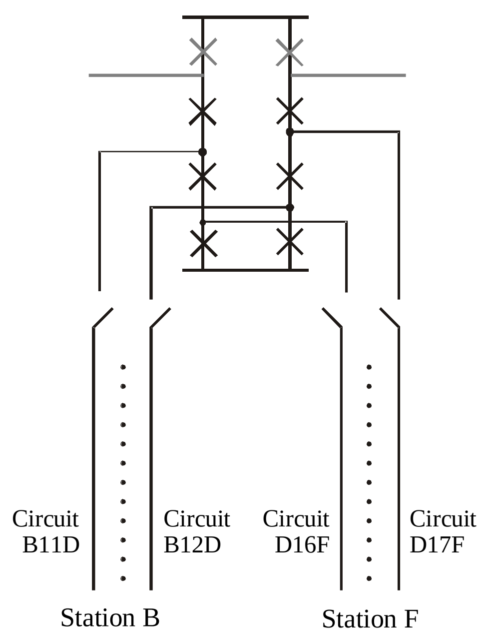
In "breaker-and-a-third" layouts the ideal location for autotransformers and generators is in the middle of the diameter as shown.

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



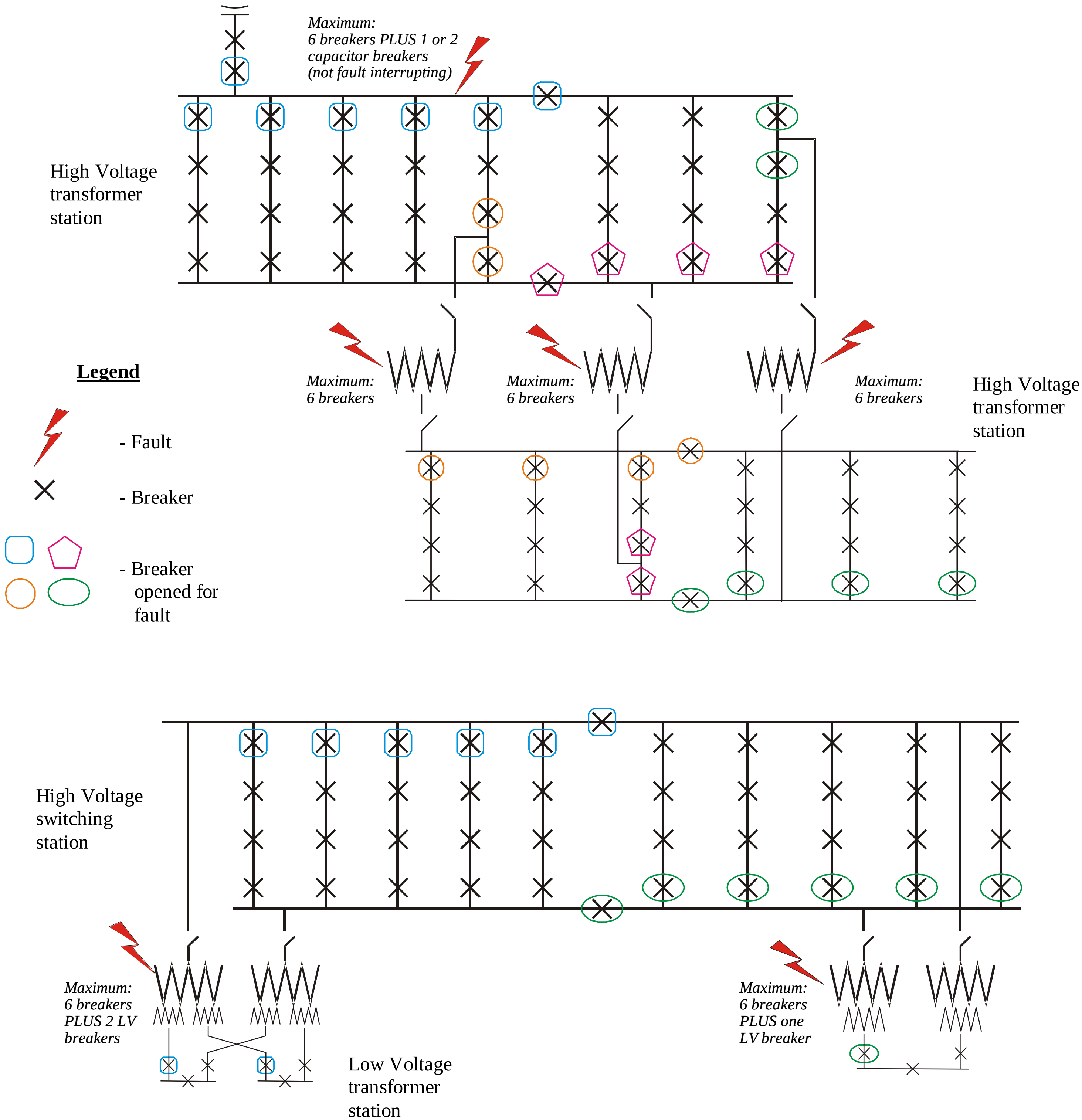
B.3.2 Bus Balance

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.



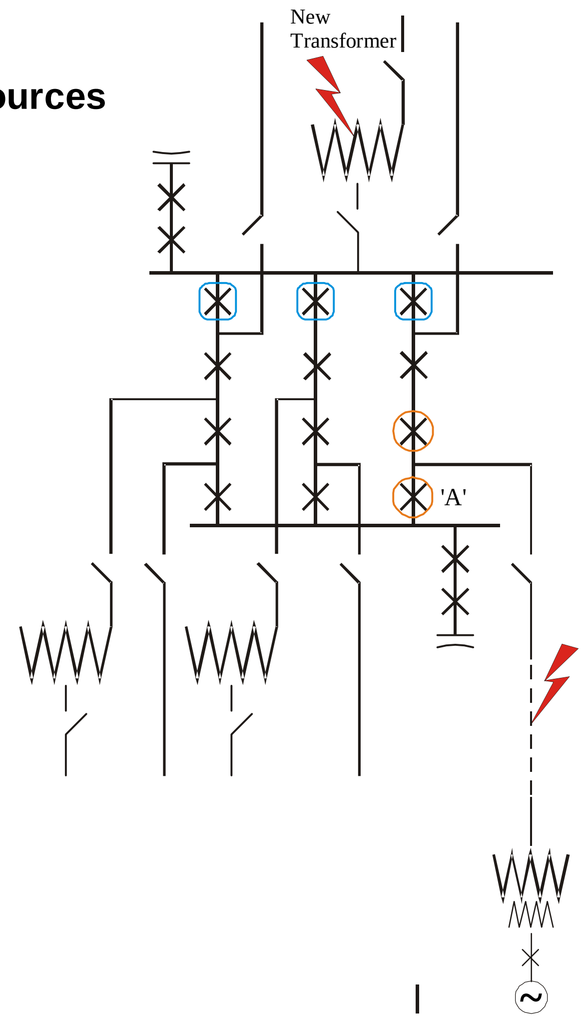
B.3.4 Separation of Reactive Power Sources

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.)

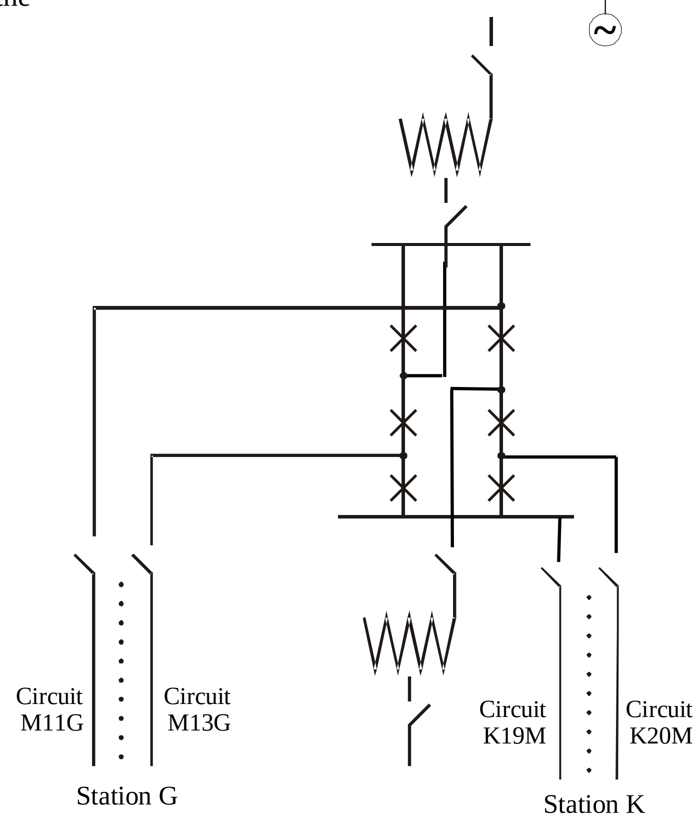
Per B.3.1, the ideal location of a generator is in the centre of a diameter (where the autotransformers are connected on the layout shown). The generator termination at the location shown is not ideal. A single-element contingency with breaker failure would result in the simultaneous loss of the generator 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.

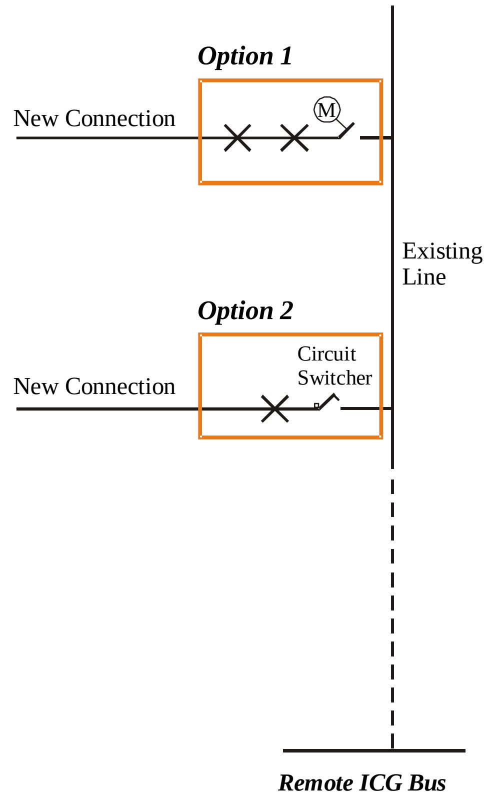


B.3.6 Connections Without Transfer Trip

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.

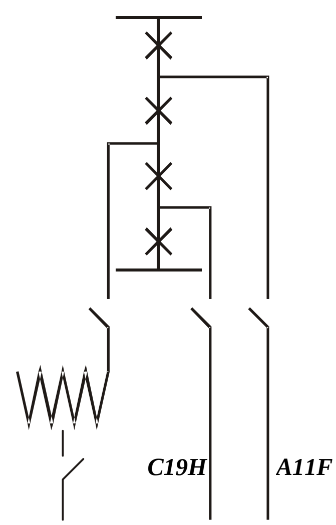
In Option 1, a line fault would initiate tripping of both breakers simultaneously, thereby addressing concerns about possible breaker failure if only a single breaker were used. This arrangement must include a motorized *disconnect* to provide 'physical' isolation of the new line from the *IESO-controlled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

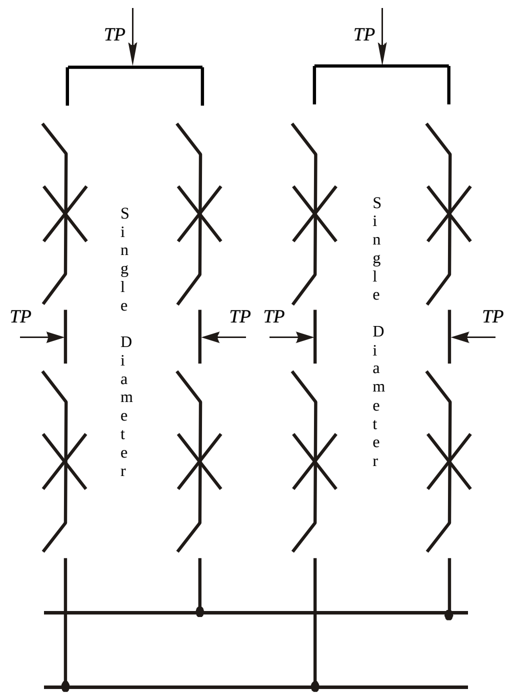


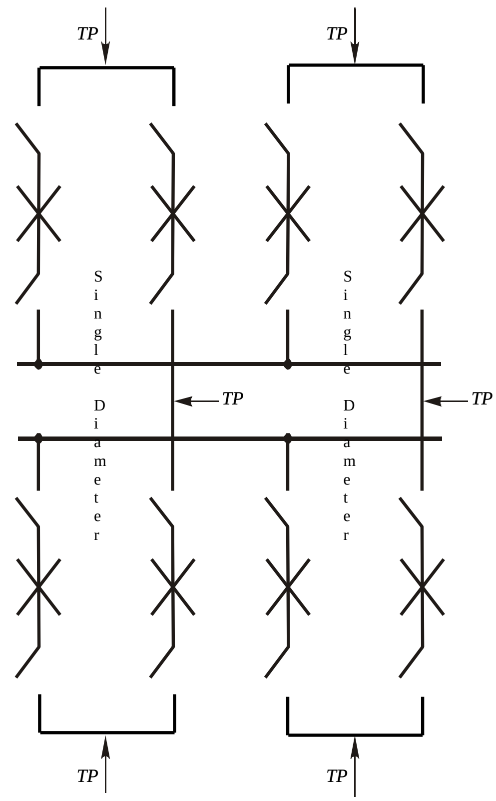
B.4 Physical Station Layouts

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*.

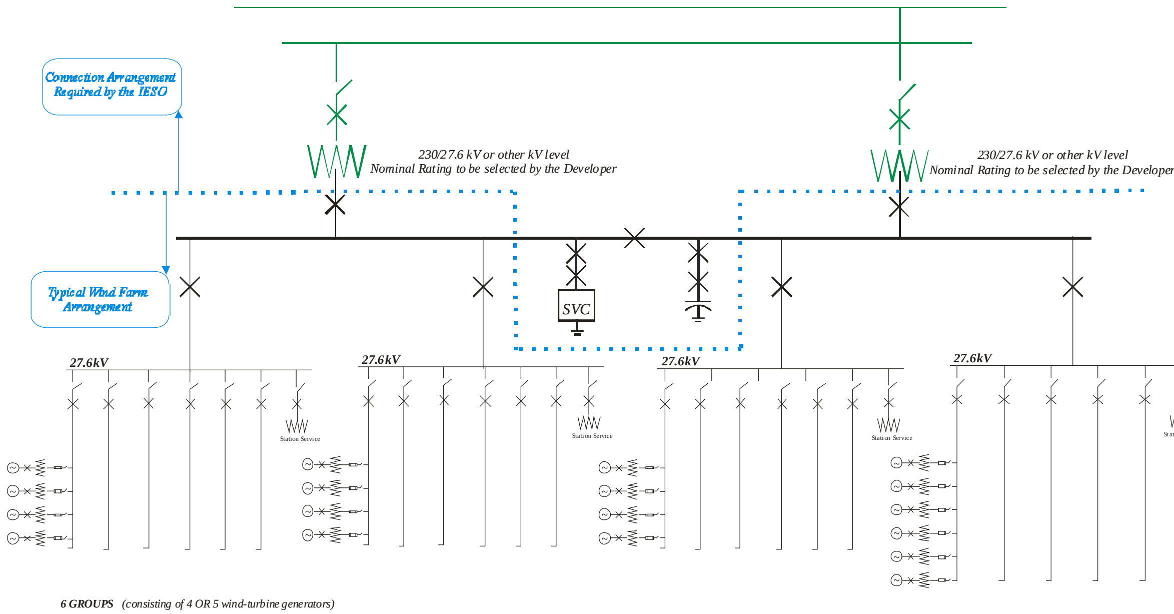
11. Line taps and step-up transformers connect to both circuits of a double-circuit-line (figure attached). The *facility* must be designed to balance the loading on both circuits of a double-circuit line.

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.

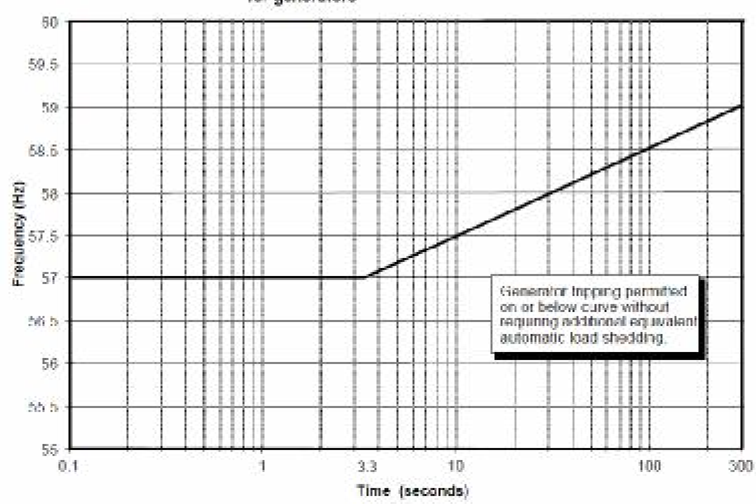
Automatic Voltage Regulator

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



Generation Facility Connection Options

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

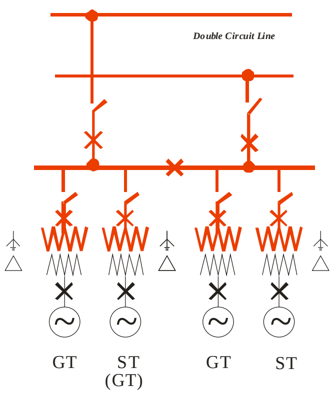


Figure 1 (Low Voltage Breakers are Optional)

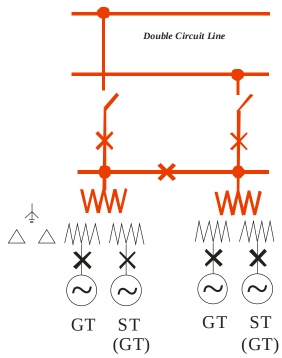


Figure 2

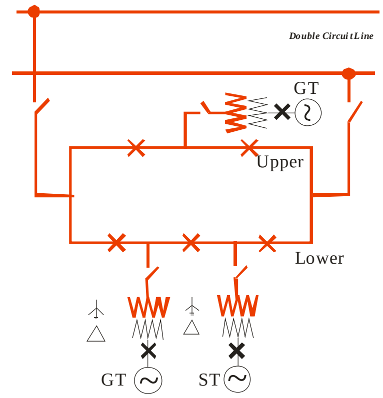


Figure 3

Typical Connection Arrangements
for Generation Facilities Rated Higher than 500 MW

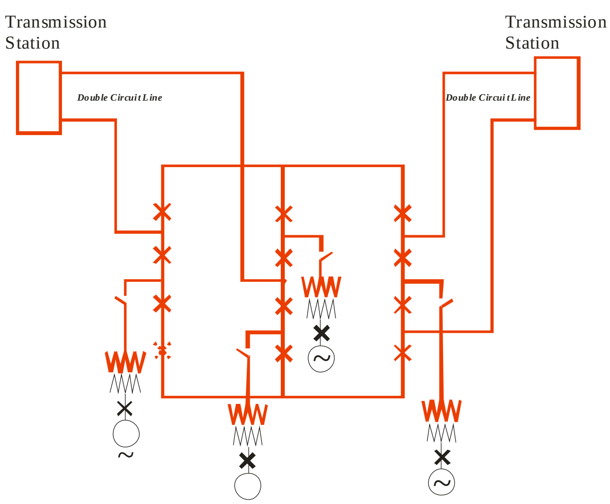


Figure 4

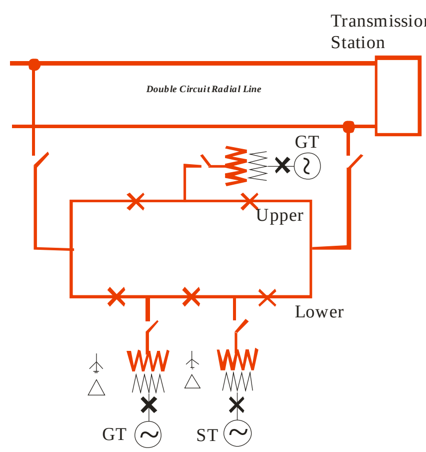


Figure 5

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	

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