POLICY

Market Manual 7: System Operations

Part 7.4: IESO-Controlled Grid Operating Policies

Issue 33.0

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

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

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Related Documents

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MDP_PRO_0040	Market Manual 7.1: System Operating Procedures

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Table of Changes

Reference (Section and Paragraph)	Description of Change
Section 3	Removed all non-policy content related to Communications. All non-policy related communications content can be found in Market Manual 7.1, section 3.
Section 4.1.2	Replaced references to “System Status Report” and “Security and Adequacy Assessment Report” with “Transmission Facility All in Service Limits Report” and the “Transmission Facility Outage Limits Report”.

Market Manuals

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

Market Policies

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

A list of the other component parts of the "System Operations Manual" is provided in "Part 7.0: "System Operations Overview", in Section 2, "About This Manual".

Conventions

The *market manual* standard conventions are as defined in the "Market Manual Overview" document.

– End of Section –

1. Introduction

1.1 Purpose and Background

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

- Provide guiding principles for the development of both internal and external operating procedures, and
- Provide guidance to *IESO* operating staff when confronted with an operational situation that is not addressed in an operating procedure or a *market rule.*

This initial set of operating policies were taken from existing *IESO* and Ontario Hydro operating policy documents and revised where required to be consistent with: the new market structure *market rules*, obligations and authorities, and the applicable *NERC reliability standards* and *NPCC* criteria and guidelines. Revisions and additions to these policies will be made as required.

The introduction of competition in generation and supply of electricity and of customer choice has substantially replaced the traditional framework. To direct reliable operation of the *IESO-controlled grid*, including *security* and supply *adequacy*, the *IESO* will, to the extent practicable, use available market mechanisms. Where the *IESO* determines such mechanisms are unable to achieve reliable operation, it will take additional actions in accordance with the policies contained herein.

1.2 Scope

These policies apply to the *IESO* in its role to direct the reliable operation of the *IESO-controlled grid*.

These policies are in compliance with the applicable standards, policies and criteria established by *NERC* and *NPCC*, along with the "*Electricity Act, 1998*" and the "Market Rules".

1.3 Overview

Section 1 is an introduction, outlining the purpose and scope of the policies. The remaining sections detail policies in the following subject areas:

- Section 2 - Operating Authority
- Section 3 - Communications
- Section 4 - Reliability
- Section 5 - Outage Management
- Section 6 - Operation Planning

Appendix B details specific *reliability standards* and *security* criteria. Appendix C defines the structure of a *security limit*. Appendix D details restrictions on the use of *Special Protection Systems* during a *high-risk operating state*. Appendix E details criteria for selection of load and generation rejection and generation runback.

1.4 Roles and Responsibilities

The *IESO* is responsible for directing the operation and maintaining the *reliability* of the *IESO-controlled grid*.

It is the responsibility of *IESO* staff to adhere to these policies in their activities in directing the reliable operation of the *IESO-controlled grid*.

Maintenance of these policies is the responsibility of the *IESO*.

1.5 Contact Information

As part of the *participant* authorization and registration process, *applicants* are able to identify a range of contacts within their organization that address specific areas of market operations. The *IESO* will seek to contact these individuals for activities documented within this procedure, unless alternative arrangements have been established between the *IESO* and the *market participant*. If a *market participant* has not identified a specific contact, the *IESO* will seek to contact the Main Contact established during the *participant* authorization process, unless alternative arrangements have been established between the *IESO* and the *market participant*.

If you wish to contact us, you can email *IESO* Customer Relations at customer.relations@ieso.ca or contact us by telephone or mail. Our telephone numbers and mailing address can be found on the IESO website (http://www.ieso.ca/Pages/Contact-Us.aspx). Customer Relations staff will respond as soon as possible.

– End of Section –

2. Operating Authority

The *IESO* is responsible for directing the operation and maintaining the *reliability* of the *IESO-controlled grid*. This responsibility is assigned to the *IESO* in the "*Electricity Act, 1998*" Section 5(c) and in the "Market Rules", Chapter 5 Section 3.2, and is a condition of the *IESO License*. The *IESO* shall have the operating authorities necessary to meet this responsibility including the authority to direct reliable operation of the *IESO-controlled grid* as well as to monitor and enforce compliance with the applicable *reliability standards*.

Operating authorities of *IESO* and *market participant* shall be clearly established to facilitate secure and reliable operation of the *IESO-controlled grid*. *IESO* authorities shall recognize and respect the authority of *market participant* to take independent action to prevent damage to their equipment, to prevent safety hazards to their employees or the public or to prevent environmental damage.

The *IESO* authorities shall be consistent with *NERC reliability standards* and *NPCC* criteria and guidelines related to authorities and responsibilities for the *IESO* as *control area operator* and *security coordinator*.

The *IESO* shall exercise its operating authorities within the framework of *NERC reliability standards* and *NPCC* criteria and guidelines, *operating agreements*, *interconnection agreements*, *market rules* and other market documentation.

– End of Section –

3. Communications

IESO communication procedures shall comply with *NERC* reliability standards and *NPCC* directories related to communications, as well as applicable *Market Rules*. *IESO* requirements for communications are located in Market Manual 7.1: System Operating Procedures, section 3.

– End of Section –

4. Security

Reference: Market Rules, Chapters 4 and 5

4.1 Security Limits

4.1.1 Overview

Security limits are technical, rather than economic, constraints on the operation of a power system that are intended to ensure that the *IESO-controlled grid* meets defined *reliability standards*. The *reliability standards* are set by *NERC and NPCC* and are available on the *NERC* and *NPCC* websites.

The *IESO* will establish *security limits* that seek to maximize the power transfer capability of the *IESO-controlled grid* within the *security* criteria imposed by *NERC*, *NPCC* and *market rules*. These *security limits* will respect the equipment capabilities that are specified by *market participants* and the voltage ranges that are required by *transmitters* and *distributors* to deliver acceptable voltage to their customers.

Changes to *security limits* are triggered by such things as:

- Addition or removal of a transmission line or other transmission equipment,
- Addition or removal of generation,
- Change in load level or distribution,
- Change in operating state (*normal, emergency, high risk*),
- Change in weather,
- *Emergencies* in neighbouring *control areas*,
- Change in capability of existing equipment, and
- Arming or disarming *special protection systems*.

Since *security limits* are affected by equipment *outages*, it is important that *outage* requests for planned work include all equipment that is required out of service to do that particular job. If additional *outage* requirements are identified after approval of the *outage*, there is a risk that the work will have to be cancelled because it conflicts with other approved *outages*, or because there is insufficient time to calculate *security limits* for the different configuration. (See Market Manual 7.3: Outage Management for more information on this process.)

Security limits are frequently specified in the form of maximum power flows and associated minimum voltages at important interfaces on the power system. For example, the sum of the power flows on all of the transmission lines into a particular 230kV transformer station should not exceed 400MW at a minimum voltage of 238kV. Different limits may apply in each of the *normal, emergency*, and *high-risk operating states*.

Security limits are formulated as linearized constraints, to facilitate market operation, with significant *outages* as parameters. If *outages* or other changes to the base network configuration cause changes to *security limits*, the revised *security limits* will be publicized.

Appendix C illustrates a hypothetical example of a *security limit*.

4.1.2 Publication

Security limits will be posted publicly in the Transmission Facility All in Service Limits Report and the Transmission Facility Outage Limits Report for the specific network configurations that are planned in those time periods. The accuracy of the *security limits* will improve as real-time approaches.

Longer-term forecasts and routine reviews will also provide information about *security limits*.

– End of Section –

5. Reliability

The *IESO* will direct the operation of the *IESO-controlled grid* to meet all applicable *NERC reliability standards* and *NPCC* criteria and guidelines[1].

In directing the operation of the *IESO-controlled grid*, the *IESO* will adhere to the following principles:

- PREVENT System Disturbances resulting from contingencies that the *IESO-controlled grid* is required to withstand,
- CONTAIN System Disturbances to that portion of the *IESO-controlled grid* initially affected, and
- MINIMIZE the effect of System Disturbances on the reliable operation of the *IESO-controlled grid,* the *IESO-administered markets* and *market participants.*

The *IESO* will direct *market participants* to act/not act so as to maintain the *IESO-controlled grid* in a *normal operating state*. The *IESO* will also act or refrain from acting where doing otherwise is likely to lead to a *high-risk*[2] or *emergency*[3] *operating state* (Chapter 5, Section's 2.4.2, 2.3.2, and 5.1.2.6 of the *market rules*).

For those areas where the *IESO* has determined that the consequences of *contingency event*s will not have an adverse impact on the *interconnected system* in northeastern North America (i.e. non-*NPCC* impactive areas) (and *local areas*), the *IESO* will develop and *publish*, in consultation with *transmitters*, *market participants* and stakeholders, the appropriate operating criteria and standards. The *IESO* will direct operations in these areas in accordance with these operating criteria and standards.

For those areas where the *IESO* has determined that the consequences of *contingency event*s will not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* (i.e. "*local areas*"), the *IESO* will apply the same *reliability standards* and *security* criteria used before *market commencement date*.

[1] *NPCC* Type "A" Documents (www.npcc.org); *NERC Reliability Standards* (www.nerc.com)

[2] *High Risk Operating State* definition:

> "Market Rules": "when the observance of *security limits* under a *normal operating state* will expose the *integrated power system* to a significantly higher than normal probability of one or more *contingency events* and associated consequences, or of a condition that may lead to, but is not yet, an *emergency*." (Chapter 5 Section 2.4.1)

[3] *Emergency Operating State* definition

> "Market Rules": " when observance of security limits under a normal operating state will either: require curtailment of non-dispatchable load; or restrict transactions on interconnected systems during an emergency on the IESO-controlled grid or on a neighbouring electricity system." (Chapter 5 Section 2.3.1)

For those circumstances/areas where the *IESO* has determined operation requires more stringent *reliability* criteria, the *IESO* will develop and *publish*, in consultation with *transmitters*, *market participant* and stakeholders, the appropriate operating criteria and standards. The *IESO* will, for those circumstances/areas, direct operations in accordance with the more stringent operating criteria and standards.

The operation of those portions of the *IESO-controlled grid* where the consequences of *contingency events* can have a significant adverse impact on the *interconnected systems* in the MAPP Region are to be directed in accordance with the IESO- Manitoba and the IESO-Minnesota Power Interconnection Agreements**.**

The *IESO-controlled grid* is also *connected* to the East Central Area Reliability Council (ECAR), via tie-lines with Michigan. In general the *IESO* operates in accordance with *NPCC* criteria and Michigan operates in accordance with ECAR criteria. Concerning operation of the tie-lines between the *IESO-controlled grid* and Michigan, the most restrictive criteria will be used pursuant to the applicable agreement between the *IESO* and the appropriate Michigan authority.

5.1 High-Risk and Emergency Operating States

The *IESO* will direct the operation of the *IESO-controlled grid* under *high-risk* or *emergency operating states* in accordance with the *market rules*, applicable *NERC reliability standards*, *NPCC* criteria and guidelines, and *IESO* standards[4] (Chapter 5, Section 5.8 and 5.9 of the *market rules*).

The conditions under which a *high-risk operating state* may be declared are included in "Market Manual 7: System Operations, Part 7.1: System Operation Procedures".

In a *high-risk operating state* the *IESO* will temporarily and selectively increase the level of *IESO-controlled grid security* by applying High-Risk Security Limits. The *IESO* will also take additional actions as required in order to maintain an acceptable level of *IESO-controlled grid security*. This may include actions such as rejection, revocation or recall of equipment and *facility outages*. These additional actions will only be taken when necessary:

- To maintain the acceptable level of *security*, and
- To allow, after a recognized contingency, the *IESO* to be able to re-establish an acceptable level of *security* and re-prepare the *IESO-controlled grid* within the time permitted.

Under internal and external (i.e. inside or outside the *IESO-controlled grid*) *high-risk* and *emergency operating states*, control actions by the *IESO* shall be structured in a manner which will first preserve system reliability and then restore normal operation of *IESO-administered markets* as soon as practicable (Chapter 5, Section 7.7.2 of the *market rules*). Also, the *IESO* will strive to achieve an

[4] *NPCC* Directory 1: Design and Operation of the Bulk Power System (section 5.5: Transmission Operating Criteria)*, NERC Reliability Standards* - EOP series

acceptable level of *security*[5] for the *IESO-controlled grid*, minimize the impact on the *IESO-administered markets*, while at the same time observing mutual protection and assistance provisions as contained in the applicable agreements between the *IESO* and other *security coordinators*.

In an *emergency operating state*, all control actions including the shedding of *non-dispatchable load* should be taken to: (Chapter 5, Section's 2.3.3, 2.3.3A and 2.3.1.1 of the *market rules*).

- Restore and maintain the level of *IESO-controlled grid security* afforded by observance of *emergency operating state security limits* (i.e. the minimum acceptable level) in:
    - Those portions of the *IESO-controlled grid* where instability could jeopardize *interconnected systems*,
    - Those portions of the *IESO-controlled grid* where instability and cascading *outages* will not affect *interconnected systems*, under High-Risk Conditions which are expected to last longer than 10 minutes,
- Avoid damage to *market participant* equipment,
- Respect environmental constraints, and
- Maintain the integrity of the *interconnected systems*.

In anticipation of, or upon declaration of an *emergency operating state*, the *IESO* will take control actions as described in Market Manual 7.1: System Operating Procedures, Appendix B.

5.2 Degraded Transmission System Performance

Where some portion of the *transmission system* is showing a recent history of degraded performance, or if degraded performance is anticipated, the *IESO* will choose from the following control actions (as applicable and in the most effective order) to safeguard the *reliability* of the *IESO-controlled grid* (as per Chapter 5, sections 2.3.2 and 5.1.2.6 of the *market rules*):

- Defer routine maintenance work
- Reject and/or revoke any *planned outages* associated with the affected portion of the *transmission system* that may have an adverse impact on the *IESO-controlled grid*
- Recall any *planned outages* that may have an adverse impact on the *IESO-controlled grid* associated with the affected portion of the *transmission system*
- If a transmission station is showing degraded performance, request the *transmitter* to staff the station either during periods of routine switching, during periods of high risk where there is a higher likelihood of equipment operation or 24/7 depending on the severity of equipment degradation

[5] The minimum acceptable level of *IESO-controlled grid security* is the level afforded by the observance of *emergency* operating criteria.

- Adjust the *IESO* list of contingencies assessed for *security* to account for additional elements removed from service due to equipment concerns
- Adjust use of Special Protection Schemes (SPSs) to reduce operation of affected *transmission system* equipment
- Issue appropriate direction to *generators* and other *market participants* as required to enhance *adequacy* and *reliability*

Affected *market participants* and *reliability coordinators* shall be advised as appropriate, which may include publishing information on areas with degraded *transmission system* performance. Where time permits, the *IESO* will discuss appropriate control actions with the applicable *transmitter* before implementation.

If the *IESO* determines that a *high-risk operating state* is warranted, it will be declared in accordance with applicable *reliability standards* and *IESO market rules* (Chapter 5, section 2.4).

5.3 Operating Under Extreme Cold Temperatures

In areas where historical trends show equipment problems during extreme cold temperatures, the *IESO* may implement control actions without the declaration of a *high-risk operating state*. If the *IESO* deems that a *high-risk operating state* is warranted, it will be declared in accordance with the *market rules*, applicable *NERC reliability standards*, *NPCC* criteria and guidelines, and *IESO* standards[6] (Chapter 5, Sections 5.8 and 5.9 of the *market rules*).

The following are actions that put into effect a coordinated and consistent approach to maintain the *reliability* of the *IESO-controlled grid* during periods of extreme cold temperatures:

1. Should there be a forecast of abnormally cold temperatures on certain portions of the *IESO-controlled grid* where problematic trends have occurred, the *IESO* will enter into discussions with the applicable *transmitters* to formulate a plan to safeguard the *reliability* of the *IESO-controlled grid* by addressing concerns with equipment operation.
2. Considerations include but are not limited to:
    - Adequacy,
    - Recent historic pattern of equipment problems during extreme cold weather,
    - The extent to which the transmitters have taken measures to alleviate the risk,
    - Recent historic pattern of forced unavailability of transmission system equipment due to switching operation in the extreme cold,

[6] *NPCC* Directory 1: Design and Operation of the Bulk Power System (section 5.5: Transmission Operating Criteria), *NERC Reliability Standards* - EOP series

- Equipment performance during extended cold periods,
- The need to have transmitters' maintenance and/or operations staff attend the site of the affected facilities or otherwise where priority dictates, and
- The IESO's overall assessment of the risks.

3. Determine which sites are affected by the extreme cold. Apply actions on a site specific basis at stations that have demonstrated a recent historic pattern of equipment problems during cold weather.
4. Actions include but are not limited to:
   - Deferring routine work,
   - Rejecting and/or revoking any *planned outages* that may have an adverse impact on the *IESO-controlled grid* associated with stations that are expected to experience the extreme cold,
   - Recalling equipment on *outage* in cases when it can be reasonably expected that switching operations will not cause equipment failures during the extreme cold,
   - Issuing appropriate direction to *generators* and other *market participants* as required to enhance *adequacy*, and
   - Accommodating urgent *outage* requests to address equipment, environmental or safety concerns regardless of the temperature.
5. Affected *market participants* and *reliability coordinators* shall be advised as appropriate.

5.4 Voltage Control

The *IESO* will *dispatch*:

- Generating unit reactive power within unit capability as specified in Appendix 4.2 of Chapter 4 of the "Market Rules",
- Reactive control devices subject to *operating agreements*,
- Reactive control devices subject to procurement contracts, and
- Resources subject to *reliability must-run contracts*,

to maintain transmission line voltages within the ranges defined in Appendix 4.1 of Chapter 4 of the "Market Rules", as well as to respect operating *security limits* and equipment ratings.

The *IESO* will *dispatch*:

- Reactive control resources subject to *operating agreements*, and
- Generating unit reactive power within unit capability,

to meet *connected wholesale customer* or *distributor* voltage needs, so long as this action does not jeopardize the ability to maintain the transmission line voltages within the ranges defined in Appendix 4.1 of Chapter 4 of the "Market Rules".

5.5 Demand Control - Manual Load Shedding

When an *emergency operating state* has been declared and reduction in *demand* is required to safeguard the *security* of the *IESO-controlled grid*, the *IESO* will use the following principles in directing which *market participant* are to undertake manual load shedding to reduce *demand*: (Chapter 5, Section 10.1.1 of the *market rules*)

- Selection of the amount and location of load to be cut will be made on the basis of solving the operating problem and maintaining adequate *IESO-controlled grid security* levels.
- When time permits, load cuts via manual rotational load shedding schemes should be spread equitably across the *IESO-controlled grid* to the extent practicable so that an equitable distribution of the cuts is attained in terms of magnitude, duration, and frequency across the *IESO-controlled grid*.

5.6 Demand Control - Under Frequency Load Shedding (UFLS)

In specifying for each *distributor* and *connected wholesale customer*, in conjunction with the relevant *transmitter*, that is subject to automatic UFLS, the number, location, size and associated low frequency settings for the discrete blocks of load, the *IESO* policy is that: (Chapter 5, Section 10.4.6 of the *market rules*)

(a) For the purpose of UFLS implementation, the province of Ontario is divided into five UFLS areas, i.e. Northwest, Northeast, West, East, and Central. The boundaries of those areas are given below.

(i) The Northwest area is bounded by the Manitoba and Minnesota *interconnections* and west of the East-West interface.

(ii) The Northeast area is bounded by east of the East-West interface and north of the Flow South interface.

(iii) The West area is bounded by the Michigan *interconnection* and west of the BLIP interface.

(iv) The East area is bounded by the New York *interconnection* at St Lawrence and east of Cherrywood and Bowmanville.

(v) The Central area is Ontario excluding the areas given by (i), (ii), (iii) and (iv), i.e. area bounded by south of North-South interface, east of the BLIP interface and west of Cherrywood and Bowmanville.

(b) In all automatic UFLS areas, there must be at least 30% of area load[7] *connected* to under-frequency relays. In order to ensure at least 30% of area load shedding is achieved while taking into account UFLS relay and feeder *outages* as well as *generation units* that trip prematurely for low frequencies[8], 35% of the load of those *distributors* and *connected wholesale customers* with a peak load of 25 MW or greater must be *connected* to UFLS relays. *Distributors* and *connected wholesale customers* with a peak load less than 25 MW are not required to provide UFLS. *Distributors* whose load spans more than one UFLS area must ensure that the required amount of UFLS is provided for their load in each UFLS area.

(c) Each *distributor* and *connected* wholesale customer shall select load for UFLS based on their load distribution at a date and time specified by the *IESO* that approximates system peak.

(d) The discrete load shedding requirements are given in (e), (f) and (g). *Distributors* and *connected wholesale customers* are allowed some time as stated in the Ontario UFLS Program Implementation Planto implement the required changes to meet these requirements. Each *distributor* and *connected* wholesale customer, in conjunction with the relevant *transmitter*, shall submit to the *IESO* their proposed implementation plan for meeting their UFLS requirements within the time set by the Ontario UFLS Program Implementation Plan.

(e) For *distributors* and *connected wholesale customers* with a peak load of 100 MW or greater, the UFLS relay *connected* loads shall be set to achieve the amounts to be shed stated in the following table.

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of MP Load	Cumulative Load Shed at stage as % of MP Load
1	59.5	0.3	7 - 9	7 - 9
2	59.3	0.3	7 - 9	15 - 17
3	59.1	0.3	7 - 9	23 - 25
4	58.9	0.3	7 - 9	32 - 34
Anti-Stall	59.5	10.0	3 - 4	35 - 37

[7] UFLS area load is the aggregate of the measured demand of Ontario's transmission zones, as per Section 4.5 (a), on a date and hour specified by the IESO. Zonal demand data can be found on the Power Data page of the IESO website. Click the **All Reports** tab, and select **Zonal Demands** from the dropdown list.

[8] The total capacity of *generation units* that do not meet the requirements of "Market Rules Chapter 4: Grid Connection Requirements" Appendix 4.2, Category 1, reported by *generators* to the IESO.

(f) For *distributors* and *connected wholesale customers* with a peak load of 50 MW or more and less than 100 MW, the UFLS relay *connected* loads shall be set to achieve the amount to be shed stated in the following table.

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of MP Load	Cumulative Load Shed at stage as % of MP Load
1	59.5	0.3	≥ 17	≥ 17
2	59.1	0.3	≥ 18	≥ 35

(g) For *distributors* and *connected wholesale customers* with a peak load of 25 MW or more and less than 50 MW, the UFLS relay *connected* loads shall be set to achieve the amounts to be shed stated in the following table.

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of MP Load	Cumulative Load Shed at stage as % of MP Load
1	59.5	0.3	≥ 35	≥ 35

(h) *Distributors* and *connected wholesale customers*, in conjunction with the relevant *transmitter* shall also shed those capacitor banks *connected* to the same station bus as the load to be shed by the UFLS *facilities*, at 59.5 Hz with a time delay of 3 seconds.

(i) Any electrical area in Ontario that may become isolated from the rest of the *IESO-controlled grid* but remain *connected* to a neighboring system during a disturbance, must contain sufficient automatic UFLS capability so that the recovery of the neighboring system will not be prejudiced.

(j) Inadvertent operation of a single under-frequency relay during the transient period following a System Disturbance should not lead to further system instability. For this reason, the maximum amount of load that can be *connected* to any single under-frequency relay is 150 MW.

5.7 Demand Control - Voltage Reductions

The *IESO* may direct a *market participant* to initiate voltage reductions to preclude or mitigate *emergency operating states*, in accordance with the Emergency Control Action List. This would include precluding or mitigating: (Chapter 5, Section 10.1.1 of the *market rules*)

- Equipment thermal overloads,
- Insufficient *generation capacity* to satisfy non-dispatchable *demand*,
- Violations of high-risk or *emergency* limits, or

- *Operating Reserve* shortfalls.

5.8 Special Protection Systems - In-Service at Market Launch

5.8.1 Governing Principles

The *IESO* will direct the operation of *Special Protection Systems* (*SPS*s) that are in-service *at market commencement date* in accordance with the applicable *reliability standards*[9] to: (Chapter 5, Section 8.1.2 of the *market rules*)

- Increase the capability of power transfers across the *IESO-controlled grid* while providing normal *security* levels, or
- Provide additional *IESO-controlled grid security* beyond that required for normal criteria contingencies.

The overriding concern in the application of an *SPS* is its potential impact on *IESO-controlled grid security* following the malfunction of an *SPS*, i.e. the failure of an *SPS* to operate when required, or the inadvertent operation of an *SPS*. All *SPSs* must therefore be classified as Type I, II or III[10] as specified in the *NPCC* criteria[11], so as to pre-determine the potential impact of a malfunction. The *IESO-controlled grid* does not currently have any Type II *SPSs* installed.

The determination of the impacts of *SPS* malfunction are carried out at theoretical study limits (i.e. without operating limit margin applied).

Type I *Special Protection Systems* may only be utilized when adequate *facilities* for achieving an acceptable level of reliable operation are unavailable for service, unless specific *NPCC* approval to utilize the *SPS* otherwise has been obtained.

Type II or Type III *Special Protection Systems* may be utilized when required, without the above constraints.

When employed, *SPSs* must be utilized in a manner, which will: (Chapter 5, Section 8.2.2A of the *market rules*)

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[9] *NPCC* Directory 07: Special Protection Systems, December 2007

[10] *NPCC* Directory 07: Special Protection Systems, December 2007; System Operations, Part 7.6: Glossary of Standard Operating Terms

[11] *NPCC* Directory 07: Special Protection Systems, December 2007

- Maintain an adequate level of *IESO-controlled grid security* while satisfying obligations to *interconnected* power *systems*.
- Ensure manageable system operation and compatibility with existing policies, strategies and procedures.
- Minimize the impact of load rejection (L/R) on the community, by distributing interruptions of prolonged duration amongst customers and satisfying *local area reliability* performance standards.

When employing an *SPS* to increase the capability of power transfers across the *IESO-controlled grid*, consideration should be given to the risks associated with possible equipment damage and customer load interruption. This assessment should be made with due regard to the probability of the occurrence of the contingency that would initiate the operation of the *SPS* and the anticipated exposure period.

5.8.2 Special Protection Systems Selection

An *SPS* should be selected as required, such that following its operation, operator action can be taken to restore *IESO-controlled grid security* consistent with these policies.

The use of an *SPS* during periods when there is an increased probability of the occurrence of the initiating condition that would operate the *SPS*, i.e. when the *IESO-controlled grid* is in *high-risk operating state*, is subject to the restrictions contained in Appendix D.

SPS selection restrictions related specifically to High Risk Conditions are considered to be High-Risk Security Limits.

An *SPS* may be used selectively to provide additional *security* beyond criteria applicable under a *normal operating state* (i.e. to respect contingencies beyond those normally recognized), in accordance with *the following criteria.*

- The additional selective use of an *SPS* in this regard must be such that it does not conflict with any arming restrictions associated with respecting criteria applicable under *a normal operating state*, specifically those associated with High Risk Conditions.
- Thus, an *SPS* can only be utilized to respect specific contingencies beyond those normally recognized, provided the required degree of contingency selection selectivity is available.

Specific criteria for selection of load rejection, generation rejection (G/R) and generation runbacks are included in Appendix E.

5.8.3 Exclusion from L/R Selection

The purpose of recognizing excluding loads from L/R selection is to minimize the impact of L/R on the community and, at the same time, maintain a L/R scheme which is operationally manageable and secure.

Loads will be considered for exclusion from the L/R selection in recognition of the following:

- Cause public safety hazard,
- Result in environmental hazards,
- *Planned* or *forced outages* equipment directly associated with L/R tripping or restoration,
- *Planned* or *forced outages* equipment which may degrade the integrity of L/R tripping or restoration, such as but not limited to: relaying, station supervisory control equipment, or
- Load transfer which result in normally excluded load is required to be supplied from a source *connected* to the L/R scheme.

The market participant request exclusion shall summit the request to the *IESO* in accordance with the "Part 7.3: Outage Management".

5.8.4 Restoration of Rejected Load

The restoration of rejected load shall be under the direction of the *IESO* shift operator. In the event the rejected load cannot be restored within 30 minutes, other relevant load may be substituted.

5.9 Special Protection Systems - Installed after Market Commencement

The *market participant* will register any new or modified *SPS* in accordance with the "Part 1.2: Facility Registration, Maintenance and Exit'.

The *IESO* will use *NPCC* criteria and guidelines in its assessment of any new or modified *SPS*- obtain appropriate approvals from *NPCC*.

The market participant will notify the *IESO* prior to placing in-service any new or modified *SPS* in accordance with the "Part 7.3: Outage Management".

The *IESO* will direct the operation of any new *SPS* in accordance with applicable *reliability standards* as outlined in Sections 4.7.1 and 4.7.2.

5.10 Network Configuration Change Requests

A *transmitter* may propose control action and/or changes to network configurations on the *IESO-controlled grid* to maintain continuity of transmission path to individual customers *connected* to the *IESO-controlled grid* and/or manage individual *delivery point* performance. The *transmitter* proposals may include changing normal *IESO-controlled grid* open points, transferring loads to alternate supplies, etc. The *IESO* shall review and approve a proposed network configuration request unless the resulting configuration either: (Chapter 5, Section 3.2.1 of the *market rules*)

- Degrades the *reliability* of the *IESO-controlled grid*,
- Results in change(s) to operating *security limits*/transfer capability,
- Results in inconsistent application of established *security* criteria and *reliability standards*,
- Imposes additional exposure to loss of essential *station service* supply to Nuclear Generating stations,
- Exposes the *IESO-controlled grid* to additional contingencies,
- Imposes additional risk/restrictions related to post-contingency *response* to recognized contingencies, or
- Results in changes in generation *dispatch* and/or could result in a change in market clearing price and/or result in constrained on or off payments to another *market participant*.

The above principles are applicable during normal operation including *planned outages*. It is expected that *transmitter* proposals for specific situations will be identified and approved in advance as part of limitations and/operating restrictions. The *IESO* will include such pre-approved proposals in its instructions for directing the operation of the *IESO-controlled grid*.

During abnormal situations i.e. *forced outages*, responding to contingencies, system restorations, unacceptable risk to customer etc. the *IESO* may deviate from the above principles while respecting the intent to the extent possible.

5.11 Automatic Reclosure Facility

The *IESO* will use *NPCC* criteria and guidelines[12] in its assessment of automatic reclosure *facilities* on the *IESO-controlled grid* which are employed to provide quick restoration of a circuit following tripping due to transient faults. The *IESO* policy is as follows: (Chapter 5, Section 3.2.2 of the *market rules*)

- Automatic reclosure settings shall be based on *market participant* equipment impact and *market participant* supply continuity.
- A faulted circuit is automatically re-energized from a single preferred breaker with undervoltage supervision and a minimum time delay of 5 seconds. In areas where studies indicates that higher speed reclosure has no impact on the *security* of the *IESO-controlled grid*, reclosing with a time delay of less than 5 seconds may be considered.
- The circuit should be automatically re-energized at the end remote from a generating station to avoid or reduce any shock loading of the generating units in the event of an unsuccessful reclosure. The breaker chosen for the re-energization of the circuit should be the one that

[12] *NPCC* Document B-1: Guide for the Application of Autoreclosing to the Bulk Power System.

would result in the least disruption in the event of a breaker failure upon an unsuccessful reclosure.

- The remaining breakers should be automatically reclosed with synchrocheck supervision, unless there is no electrically close generating station, then voltage presence supervision with a nominal time delay of 0.5 seconds may be used. For reclosing at thermal *generator* stations, the synchrocheck angle selection should not allow reclosures which result in the instantaneous power changes on any *generator* exceeding 0.5 per unit of its MVA rating.

- Automatic reclosure shall not be used to re-synchronize a generating unit that has separated from the *transmission system*.

- Operating *security limits* are derived such that the system must successfully withstand an unsuccessful automatic reclosure (open-close-open sequence) operation.

5.12 Islanding

- Where a single contingency can create an island and where voltage or frequency cannot be monitored and controlled, *IESO* policy shall be to take pre-contingency control actions, such as arming of a *SPS*, or configuration change to collapse the under-generated island. For *local areas*, the *IESO* will not commit additional generation pre-contingency to allow a post-contingency island to survive (Chapter 5, Section's 3.2.1 and 5.1.2.1 of the *market rules*).
- Where a single contingency results in an over-generated island and where voltage or frequency can be monitored and controlled, *IESO* will allow the island to operate provided:
    - That the island is restricted to a well-defined part of the *IESO-controlled gird*, and
    - *IESO* studies show that voltage and frequency can be controlled to within acceptable steady state values.

When available, *SPS*s may be used to ensure that an over-generation island will continue to operate following a contingency.

- For areas where the consequences of a contingency cannot be shown to be restricted to a well-defined part of the *IESO-controlled grid*, the *IESO* will take pre-contingency actions to avoid, where possible, a single contingency resulting in an island, and will constrain units on to ensure an over-generated island.

- For those areas where there are specific practices in place to deal with potential islanding, these practices will be documented and must be followed.

– End of Section –

6. Outage Management

6.1 Overall Policy

In its role to review, assess, approve, reject, revoke and recall proposed *outages* of *market participant registered facilities* and associated equipment, the *IESO* objective is to maintain reliable operation of the *IESO-controlled grid*. In its review, assessment, approval, rejection, revocation and recall of *outages*, the *IESO* will comply with the applicable *market rules*. The *IESO* will reject, revoke or recall an *outage* if required to maintain reliable operation of the *IESO-controlled grid*, including overall *adequacy* of the *IESO-controlled grid* (Chapter 5, Section 6.2 - 6.4B of the *market rules*).

The *IESO* will deal fairly and appropriately with each *market participant* and comply with the applicable *market rules* and procedures. The *IESO* will provide timely information that is accurate to the best of its knowledge to each *market participant* so as to facilitate *market participant* co-ordination of *outages* and the market mechanisms to resolve *outage* conflicts.

The *IESO* will work with neighboring utilities, transmission asset owners and *control areas* to influence, to the extent possible, *outages* of *facilities* and equipment outside of the *IESO-controlled grid*, whose *outage* would impact the reliable operation of the *IESO-controlled grid*.

- End of Section -

7. Assessment of System Security and Adequacy

7.1 Overall Policy

The *IESO* will develop, maintain and implement plans for the reliable operation of the *IESO-controlled grid* to meet all applicable *NERC reliability standards* and *NPCC* criteria and guidelines[13].

The *IESO* will develop and *publish* load forecasts, *security* and *adequacy* assessments, pre-dispatch and *real-time schedules* to meet all applicable *market rules*[14] and procedures[15].

7.2 Determination of Generation and Transmission Adequacy

When assessing generation and transmission *adequacy*, the *IESO* will consider the following factors: (Chapter 5, Section 7.1.1 of the *market rules*)

- Forecast primary *demand* (non-dispatchable + losses) and *dispatchable load*,
- Load forecast uncertainty,
- Additional contingency allowance,
- Forecast generation availability, capacity and *energy* capability, including the available but not operating (ABNO) units and generation external to Ontario and tie-line capability from outside the *IESO-controlled grid,*
- Forecast transmission *facility* capability, planned availability and *forced outages*,
- Applicable operating *security limits*, and
- Acceptable voltage ranges.

When assessing generation *adequacy*, the *IESO* will compare forecasted *demand* to available resource capacity and *energy*, including available generation external to Ontario. For the purposes of identifying

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[13] *NERC Reliability Standards - TOP-002, EOP-001, EOP-003, EOP-005 and EOP-008*;

NPCC Documents: A-2 - Basic Criteria for Design and Operation of Interconnected Power Systems; B-8 - Guidelines for Area Review of Resource *Adequacy*

[14] “Market Rules” Chapters 5 and 7

[15] “Market Manual 2: Market Administration, Part 2.8: Providing 10-Year Forecast and Assessment Information Requirements and Report”

potential *adequacy* problems and/or exigencies potentially impacting on the coordination of *outages* that could give rise to shortfalls in *generation capacity*, the *IESO* will use the following criteria for *normal operating states*:

- For the *dispatch day* and two days following the *dispatch day* assessment, an acceptable level of *adequacy* is achieved if:
    - Available resources, based on installed capacity, estimated imports and *outage* information, exceed forecasted primary *demand* by at least the *Operating Reserve* requirement, and
    - Available resources, based on *energy* production of *energy*-limited resources, installed capacity of non-*energy*-limited resources, estimated imports and *outage* information, exceed forecasted primary *demand* in MWh.
- In the event that *IESO* determines that there is not an acceptable level of resources in the short-term, the *IESO* will take necessary actions such as:
    - *Publishing* information necessary to allow the market to react to *adequacy* concerns,
    - Activating *reliability must-run contracts* to address *local area adequacy* only (i.e. not permitted to address lack of overall system generation *adequacy*),
    - *Outage* rejection, revocation, recall, and
    - Issuing system advisory notices with the expected actions to be taken (e.g. voltage reductions, public appeals, load shedding).
- For the balance of assessments up to 14 days following the *dispatch day*,
    - During the months between March and November, inclusive, an acceptable level of *adequacy* is achieved if forecast available resources, based on installed capacity and *outage* information, exceed forecasted primary *demand* by the *Operating Reserve* requirement plus the next largest half-contingency plus load forecast uncertainty.
    - During the months of December, January and February, inclusive, an acceptable level of *adequacy* is achieved if forecast available resources, based on installed capacity and *outage* information, exceed forecasted primary *demand* by the *Operating Reserve* requirement plus the next largest contingency plus load forecast uncertainty.
- For the assessment from day 15 following *dispatch day* out to the end of week 4 following the *dispatch* week,
    - During the months between March and November, an acceptable level of *adequacy* is achieved if
        - Forecast available resources, based on installed capacity and *outage* information, exceed forecasted primary *demand* by the linear interpolation between the *Operating Reserve* requirement plus the next largest half contingency plus load

forecast uncertainty and an amount such that the Loss of Load Expectation (LOLE) is less than 0.1 days per year, consistent with *NPCC* requirements[16], and

    - Available resources, based on *energy* production of *energy*-limited resources, installed capacity of non-*energy*-limited resources, estimated imports and *outage* information, exceed forecasted primary *demand* in MWh.

  - During the months of December, January and February, an acceptable level of *adequacy* is achieved if forecast available resources, based on installed capacity and *outage* information, exceed forecasted non-dispatchable *demand* by an amount such that the Loss of Load Expectation (LOLE) is less than 0.1 days per year, consistent with *NPCC* requirements.[18]

- For the 18 month and 10 year assessments an acceptable level of *adequacy* is achieved if forecast available resources exceed forecasted *demand* by an amount such that the Loss of Load Expectation (LOLE) is less than 0.1 days per year, consistent with *NPCC* requirements.[18]

When assessing transmission *adequacy*, the *IESO* will compare forecast transmission flows with the applicable operating *security limits* under a range of load conditions and *generator* and transmission *facility* availability conditions. Transmission is considered adequate if forecast loads can be supplied without exceeding the applicable operating *security limits*, and acceptable system voltages can be maintained.

7.3 Determination of System Security

The *IESO* will maintain *IESO-controlled grid security* such that satisfactory post-contingency performance will be experienced following recognized contingencies of specified severity as described in Appendix B.

The *IESO* will take all necessary steps including the interruption of *non-dispatchable load*, except in non-*NPCC* impactive areas during normal system conditions, to restore the operation of the *IESO-controlled grid* to an *emergency operating state* respecting corresponding limits within the target restoration times specified in *"Market Rules"* Chapter 5, Section 5.10.2.1. The criteria for deriving the *emergency operating state* limits are described in Appendix B. The following summarizes the criteria and actions used to maintain *security* throughout the *IESO-controlled grid* and to avoid or minimize shedding of *non-dispatchable load*.

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[16] *NPCC* Document A-2: Basic Criteria for Design and Operation of Interconnected Power Systems

Criteria	Action	NPCC Impactive Area	NON-NPCC Impactive Area	
			Normal System Condition	High Risk System Condition
Respect *NPCC* Criteria as per Appendix B	using all available control actions[1] including the shedding of *non-dispatchable load*	X		
Respect Non-*NPCC* Impactive Criteria as per Appendix B	using all available control actions[1] including the shedding of *non-dispatchable load*		X	X [2]
Restore security of the *IESO-controlled grid* to respect *emergency* condition limits following a recognized contingency	using all available control actions[1] including the shedding of *non-dispatchable load* post-contingency	X		X
Restore security of the *IESO-controlled grid* to respect *emergency* condition limits following a recognized contingency	using all available control actions[1] without shedding of *non-dispatchable load* post-contingency		X	

Notes:

1. To avoid or to minimize *non-dispatchable load* shedding, in addition to the *emergency operating state* control actions listed in Market Manual 7.1, Appendix B, the following control actions may be used where appropriate:
    - Load transfers
    - Network configuration change, only if it does not contribute to additional risks to *generator* or load
    - Phase shifter adjustment
2. If limits are available, in general limits are not available for the Non-*NPCC* Impactive area during high-risk condition.

7.4 Operating Reserve

The purpose of *Operating Reserve* is to ensure there is adequate generation to match the load in order to: (Chapter 5, Section 4.5.1 of the *market rules*)

- Cover or offset unanticipated increases in load during a *dispatch day* or *dispatch hour*,
- Replace or offset capacity lost due to the *forced outage* of generation or transmission equipment, or
- Cover uncertainty associated with the performance of *generation facilities* or *dispatchable loads* in responding to the *IESO's dispatch instructions*.

Operating Reserve shall be distributed so as to ensure that it can be utilized for any contingency resulting in generation loss without exceeding equipment or *transmission system* limitations and so that the requirements of "Area Reserve" in Section 6.5 are met.

Operating reserve requirements will be defined in accordance with the policies of the relevant *standards authorities*[17].

Voltage Reductions will only be included in *Operating Reserve* when the market mechanisms to provide *Operating Reserve* do not provide an adequate amount of *Operating Reserve*.

7.5 Area Reserve for Load Security

The *IESO* will schedule area reserve using available means including market mechanisms such as requesting *offers* from *generators* and *bids* from *dispatchable load* to avoid shedding *non-dispatchable load* and to respect operating *security limits* following permanent loss of single elements of generation or transmission (Chapter 5, Section 4.5.5 of the *market rules*).

During abnormal conditions on the *IESO-controlled grid,* the *IESO* may schedule area reserve that results in carrying total reserve more than the normal required *Operating Reserve*. The *IESO* may also take additional control action to maintain area reserve (e.g., under *high-risk operating state*).

In some portion of the system, installed *facilities* may not meet design requirements or supply *reliability* may deviate significantly from standard. These will require individual assessment in situations where market mechanisms do not meet Area reserve requirements, in addition to the *emergency operating state* control actions listed in Market Manual 7.1, Appendix B, the following measures should be included as area reserve where appropriate to avoid or to minimize *non-dispatchable load* shedding:

1. Load transfers,
2. Network configuration change, only if it does not contribute to additional risks to the *generator* or load, and
3. Phase-shifter adjustment.

- End of Section -

[17] *NPCC* Criteria Document A-06; *NERC Reliability Standards* – BAL-002

8. Compliance

The Ontario Reliability Compliance Program (ORCP) is an Ontario-wide compliance program to promote and improve the *reliability* of the *IESO-controlled grid* by ensuring Reporting Entities (*market participants* and the *IESO*) comply with *reliability standards*.

The ORCP includes a series of processes designed to:

- Ensure that Reporting Entities understand their *reliability* obligations,
- Monitor, detect and self-report potential non-compliance with the *reliability standards* in a timely manner,
- Attest and demonstrate compliance with the *reliability standards* actively monitored by the ORCP,
- Submit *reliability* data in response to requests from the *IESO*, and
- Remediate non-compliances and prevent recurrence.

“Market Manual 11.2: Ontario Reliability Compliance Program” details the procedural requirements for the program.

- End of Section -

Appendix A: Forms

There are no forms used in this document.

– End of Section –

Appendix B: Reliability Standards and Security Criteria

Refer to *NPCC* "A" documents

Refer to Appendix 4.1 of Chapter 4 of the *Market Rules* for performance standards related to the *transmission system*:

- Frequency variations, and
- Voltage variations.

B.1 Satisfactory Post-Contingency Performance

The *IESO-controlled grid* must display satisfactory performance following a fault:

- The *IESO-controlled grid* must be stable with all unfaulted elements remaining in service except those associated with normal fault clearance and Special Protection Schemes if employed.
- The post-contingency steady-state loading of all *IESO-controlled grid* elements must be within their ratings as provided by the *facility* owners*.*
- The *IESO-controlled grid* must be able to withstand manual energization of the faulted element without prior readjustment of generation levels unless specific instructions to the contrary are provided. Such instructions will be embodied in Operating Security Limits and will normally apply only under specified conditions of loading in instances where post-contingency conditions would present a radical departure from the normal system configuration.

The post-contingency voltage levels must be within the limits as specified in B.3.2.

B.2 Recognized Contingencies

The operating *security limits* shall be based on the following criteria:

B.2.1 NPCC Impactive Areas

Those portions of the *IESO-controlled grid* where the consequences of an *NPCC* normal criteria contingency could have a significant adverse impact on the *interconnected systems* in northeastern North America are to be operated so that satisfactory transient performance and acceptable post-contingency steady-state conditions will be experienced following the most severe of the contingencies listed below with due regard to reclosing *facilities*.

a. When the *IESO-controlled grid* is in *normal operating state*, operating *security limits* will be based on the following recognized contingencies

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

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

(iii) A permanent phase to ground fault on any *generator*, transmission circuit, transformer, or bus section**,** with delayed fault clearing.

(iv) Loss of any element without a fault.

(v) A permanent phase to ground fault on a circuit breaker, with normal fault clearing.

(vi) Simultaneous permanent loss of both poles of a direct current bipolar *facility*.

(vii) The failure of a circuit breaker associated with a Special Protection Scheme to operate when required following: 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.

b. When the *IESO-controlled grid* is in an *emergency operating state*, operating *security limits* based on the following contingencies will apply:

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

(ii) Loss of any element without a fault.

c. When the *IESO-controlled grid* is in a *high-risk operating state*, operating *security limits* will be developed in order to avoid or to minimize the frequency or occurrence of specific consequences arising from design criteria contingencies, or to respect contingencies beyond design criteria (High-Risk Security Limits). In general, the development and application of High-Risk Security Limits to avoid or to minimize the frequency of occurrence of specific consequences are considered when the observance of Normal Operating State Security Limits includes:

(i) The use of generation rejection or automatic load rejection for a single element contingency.

(ii) The use of a significant amount of generation rejection or automatic load rejection for a double element contingency.

In specific cases, High-Risk Security Limits may be used to provide a *security* level temporarily higher than design standard (e.g. loss of two circuits versus loss of one circuit) based upon operating experience.

B.2.2 Non-NPCC Impactive Areas

For those areas where the *IESO* has determined that the consequences of the contingencies specified in a) above will not have an adverse impact on the *interconnected systems* in northeastern North America (i.e. " non-*NPCC* impactive areas"), the *IESO* will use the following *reliability standards* and *security* criteria:

a. Only single contingencies are recognized:

  (i) the loss of an element without a fault, and

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

b. With all elements in service, a recognized contingency shall not result in load loss except where such load is directly *connected* to the faulted element or the load is intentionally interrupted via the operation of a Load Rejection *SPS* operation.

c. With one element out of service, a recognized contingency may result in load loss by configuration only or as the result of Load Rejection *SPS* operation.

d. Under multiple *outage* conditions where instability or overloads will have an adverse impact on the *interconnected systems* in northeastern North America, the criteria in section B.2.1 above must be applied.

In some portion of the system, installed *facilities* may not meet design requirements or supply *reliability* may deviate significantly from standard. These areas will require individual assessment.

B.2.3 Local Areas

For those areas where the *IESO* has determined that the consequences of the contingencies specified in a) above will not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* ("*local areas*"), the *IESO* will apply the same *reliability standards* and *security* criteria used before *market commencement date*. The *reliability standards* and *security* criteria used before *market commencement date* will be documented and must be followed. The *reliability* of *local areas* will be reviewed jointly between the *IESO* and *transmitters* at least once annually.

B.2.4 MAPP Impactive Areas

For those portions of the *IESO-controlled grid* where the consequences of contingencies specified in a) above can have a significant adverse impact on the *interconnected systems* in the MAPP Region, a jointly agreed upon criteria between the *IESO* and neighboring utilities (i.e. Manitoba Hydro and Minnesota Power) will continue to be observed until adequate *facilities* are in service.

B.3 Criteria For Derivation Of Operating Security Limits

This section sets forth the criteria to be used by the *IESO* in analyzing the results of off-line computer studies conducted to establish Operating Security Limits.

The *IESO-controlled grid* is to be operated so that satisfactory pre-contingency steady-state conditions are maintained. Transient stability of the *IESO-controlled grid* will be maintained and acceptable post-contingency steady-state conditions will be experienced following the occurrence of the most severe contingency for which the *IESO-controlled grid* is designed.

Satisfactory transient stability and pre and post-contingency steady-state behavior may be considered is assured if the Operating Security Limits are based upon the criteria stated herein.

B.3.1 Pre-Contingency Criteria

In deriving Operating Security Limits for Normal Conditions and for Emergency Conditions, the *IESO-controlled grid* must meet the criteria listed below in the steady state prior to contingency simulation.

Steady-State 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.

Damping Factor

The damping factor provides a measure of the steady-state stability margin of a power system. If an eigenvalue state-space model of the power system is available, then the damping factor (ξ) 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.

Operating Security Limits should ensure a damping factor equal to or greater than 0.03 under normal operating conditions.

B.3.2 Post-Contingency Criteria

Transient Stability Criteria

The transient stability performance of a power system is its ability to maintain synchronism between its parts when it is subjected to a loss of system element(s), usually accompanied by a fault.

The system model must meet the criteria listed below during the period of simulated real time, normally three to thirty seconds, following the most severe contingency set by the *IESO* policy with due regard to reclosure, generation rejection and/or load rejection.

Relay Margin

Following fault clearance or the loss of an element without a fault, the margin on all instantaneous and timed distance relays that affect the integrity of the *IESO-controlled grid*, including *generator* loss of excitation and out-of-step relaying at major generating stations, must be at least 20 and 10 percent, respectively.

The margin on all other relays whose operation would not affect the integrity of the *IESO-controlled Grid*, such as 115 kV or radial 230 kV circuit protections, *generator* loss of excitation and out-of-step protections on small *generating units*, those associated with transformer backup protections, must be at least 15 percent on all instantaneous relays and zero percent on all timed relays having a time delay setting less than or equal to 0.4 seconds.

For those relays having a time delay setting greater than 0.4 seconds, the apparent impedance may enter the timed tripping characteristic, provided that there is a margin of 50 percent on time. For example, the apparent impedance does not remain within the tripping characteristic for a period of time greater than one-half of the relay time delay setting.

The margin on all system relays, such as change of power relays, must be at least 10 percent.

Transient Stability Margin

The *IESO-controlled grid* must display a transient stability margin of at least 10 percent, calculated on the basis that the system must remain transiently stable if the most critical System Operating Parameter is increased to a value corresponding to a value at 10 percent higher than the Operating Security Limit.

The minimum Relay Margin Criteria should be satisfied at the appropriate Operating Security Limit.

System Dynamic Oscillations

The *IESO-controlled grid* must display damping of dynamic oscillations, if they exist. Acceptable damping is demonstrated by attenuation of the amplitude of the envelope of the oscillations for at least 10 to 20 seconds following the critical contingency.

Voltage Collapse / Stability

The *IESO-controlled grid* must display a voltage collapse/stability margin of at least 10 percent, calculated on the basis that the post-contingency voltage collapse will not occur if the most critical system operating parameter is increased to a value at 10 percent higher than the Operating Security Limit.

Post-Contingency Steady State Criteria

Following the most severe operating contingency, the *IESO-control grid* must meet the following criteria in the steady-state prior to operator intervention, when operating at the Operating Security Limit.

Post-contingency Steady-State Stability

The computed Damping Factor should be equal to or greater than 0.01 for all modes.

Post-Contingency Voltage Levels

The post-contingency voltage levels on the *IESO-controlled grid* following the most critical single and double-element contingencies specified in section B.2 must be within 5 to 15 percent of their pre-contingency levels as specified below.

			Permissible Voltage Change in Percent	
IESO-controlled Grid	*IESO-controlled grid* Condition	Contingency	Before Tap Changer Action	After Tap Changer Action
NPCC Impactive	Normal	Single-element Double-element	5 10	10 15
	Emergency	Single-element	10	15
NPCC Non-Impactive And Local Areas	Normal	Single-element	10	15
	Emergency	Single-element	10	15

– End of Section –

Appendix C: Structure of Security Limit

Different areas of the *IESO-controlled grid* may be overgenerated or undergenerated, depending upon the time. In this example, an undergenerated area is considered.

An undergenerated area of the *IESO-controlled grid* is typically constrained by post-contingency voltage declines within the area. Figure C-1 illustrates such an area and the *security limit* that might apply to it. Assume that the *security* criteria for this area require that only single element losses have to be considered, and that post-contingency voltage declines of up to 10% are acceptable.

The solid line in Figure C-1 is the locus of all of the combinations of transfers into the area that produce no more than a 10% voltage decline at any bus in the area when all 4 lines are in service before the contingency. There will be three lines left to supply the area after the contingency. The dashed line is the limit when Line 4 is out prior to the contingency. In this case, the area will be left with only two lines supplying it after the contingency.

The following equations define the *security limit* with all 4 transmission lines in service:

$$(\mathrm{P1}+\mathrm{P2}) \leq 250$$ the current-carrying capacity of Lines 1 and 2

$$(\mathrm{P3}+\mathrm{P4}) \leq 700$$ the current-carrying capacity of Lines 3 and 4

$$(\mathrm{P1}+\mathrm{P2}) \leq 400-0.8(\mathrm{P3}+\mathrm{P4})$$ the voltage decline limit

With Line 4 out of service, the constraints are:

$$(\mathrm{P1}+\mathrm{P2}) \leq 250$$ the current-carrying capacity of Lines 1 and 2

$$(\mathrm{P3}+\mathrm{P4}) \leq 350$$ the current-carrying capacity of Lines 3 and 4

$$(\mathrm{P1}+\mathrm{P2}) \leq 292-0.8(\mathrm{P3}+\mathrm{P4})$$ the voltage decline limit

Similar constraints would exist for one of Lines 1, 2, or 3 out of service.

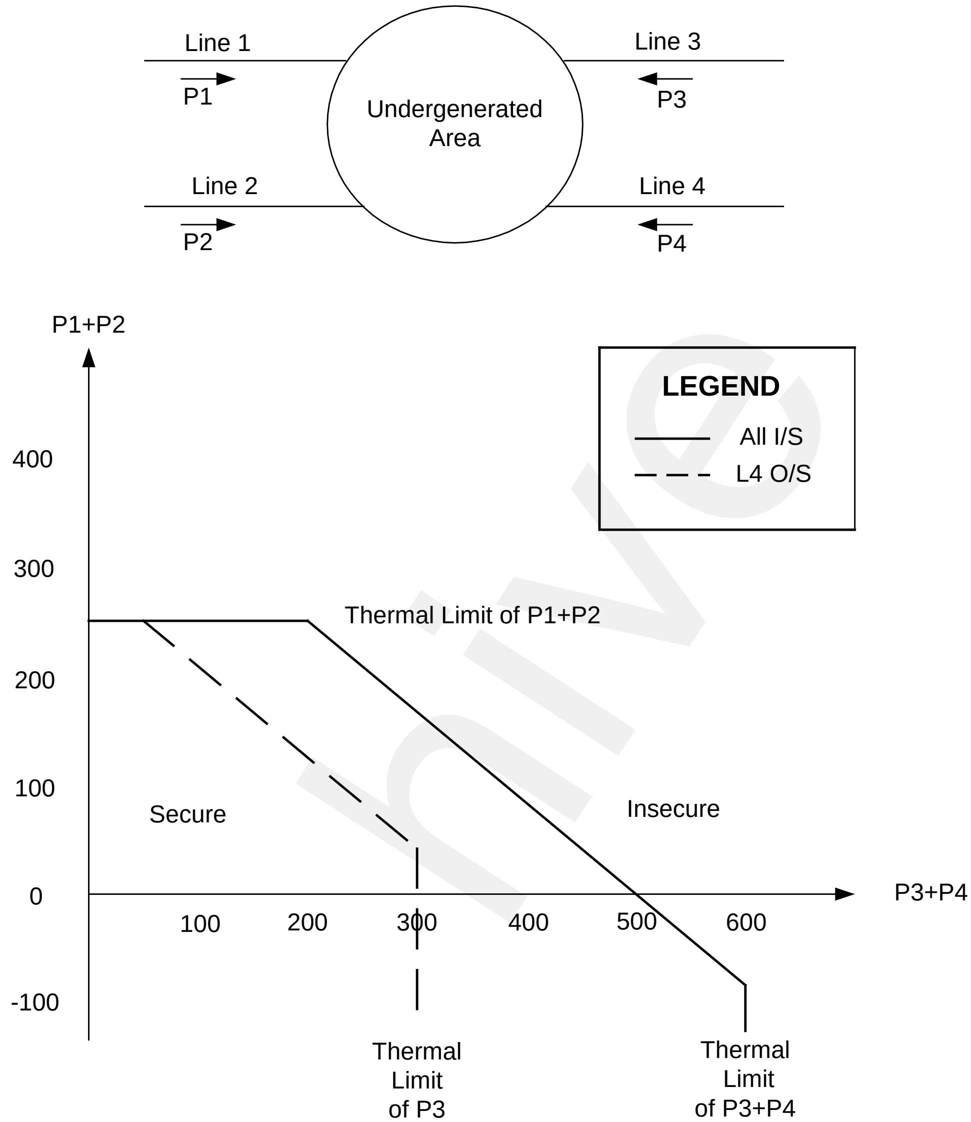

Figure C-1: Security Limit for an Undergenerated Area

– End of Section –

Appendix D: SPS Restrictions During High Risk Operating State

Refer to Notes A and B

<table>
<tr><th colspan="2">Contingency Type</th><th colspan="2">High Risk Operating State Due to Adverse Weather (refer to notes C, D and E)</th><th>High Risk Operating State Due to Conditions Other than Adverse Weather (E)</th></tr>
<tr><td rowspan="3">500 kV</td><td>Double Element Contingency</td><td colspan="2">No restrictions to G/R or L/R</td><td rowspan="7">Conditions that may lead to the declaration of a high risk operating state are specified in Section 4.2 of this document.

Under these conditions:

(1) The SPS must not be utilized if a fail-to-trip condition is suspected.

(2) In all other situations, the primary concern is the impact of a false SPS operation, and the increased exposure to load rejection. The following restrictions therefore apply:

• G/R or Generation Runback may be selected, but its use should be minimized or avoided where possible.

• L/R may be selected, as follows:
Type I applications: L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.
Type III applications: L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.</td></tr>
<tr><td rowspan="2">Single Element Contingency</td><td colspan="2">G/R is permissible, provided:
(a) its exposure is limited to outage periods or short-duration periods, or
(b) its magnitude is reduced during adverse weather periods</td></tr>
<tr><td>Type I applications:
L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.</td><td>Type III applications:
L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.</td></tr>
<tr><td rowspan="3">230 kV</td><td>Double Element Contingency</td><td colspan="2">No restrictions to G/R or L/R</td></tr>
<tr><td rowspan="2">Single Element Contingency</td><td colspan="2">G/R is permissible, provided the only other alternative is to remove the unit from service, or the unit would be automatically removed from service as a result of the initiating contingency</td></tr>
<tr><td>Type I applications:
L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.</td><td>Type III applications:
L/R is permissible, provided IESO-controlled grid security criteria could not otherwise be satisfied.</td></tr>
<tr><td rowspan="2">115 kV</td><td>Double Element Contingency</td><td colspan="2">Not observed</td></tr>
<tr><td>Single Element Contingency</td><td colspan="2">G/R is permissible, provided the only other alternative is to remove the unit from service, or the unit would be automatically removed from service as a result of the initiating contingency,</td><td></td></tr>
</table>

Contingency Type		***High Risk Operating State*** **Due to Adverse Weather (refer to notes C, D and E)**	***High Risk Operating State*** **Due to Conditions Other than Adverse Weather (E)**
		L/R is permissible, provided *IESO-controlled grid* security criteria could not otherwise be satisfied.	

(A) Conditions under which *high-risk operating state* may be declared are defined in Section 4.1. The restrictions in this table do not apply during an *emergency operating state*.

(B) *SPS* policy refers to normally recognized contingencies. An *SPS* may be selectively used to provide additional *security* beyond normal criteria, provided the above restrictions are satisfied.

(C) Weather conditions to be considered are those within the Weather Advisory Area, which is within 50 km of the circuits for which the *SPS* is selected.

(D) During extreme weather conditions, additional unrestricted *SPS* selections may be made per Note (B) to respect extreme contingencies.

(E) The Bruce *SPS* is limited to 2 unit arming and no load rejection is permitted. The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency *non-dispatchable load* shedding.

– End of Section –

Appendix E: Load and Generation Rejection and Generation Runback Selection Criteria

In addition to the following, instances where more than one of the load rejection, generation rejection or generation runback scheme could be operated for a single *contingency event* should be minimized to the extent practical.

Load Rejection Selections

a. For any specific contingency, the maximum amount of load rejection (L/R) cannot exceed 1000 MW.

b. The load rejection portion of the Bruce *Special Protection System* shall not be used in conjunction with generation rejection to maintain Bruce stability. The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency *non-dispatchable load* shedding.

c. The use of L/R is permissible only if the affected *IESO-controlled grid Delivery Points* will remain within *reliability* performance standards.

d. Where the selection of L/R is used to prevent the post-contingency thermal overloading of *IESO-controlled grid* components:

   (i) L/R may be selected whenever the post-contingency loading without such rejection would exceed the appropriate Limited Time Rating, in the amount sufficient to respect that rating.

   (ii) If the lack of fast-acting control actions combined with the complexities of post-rejection operation, will jeopardize the ability to reach long-time ratings within the appropriate “limited” time, then rejection of sufficient load to prevent loading beyond the long-time ratings will be permitted.

e. L/R should be selected to satisfy the following in order of priority:

   (i) **Security.** L/R selections must satisfy system *security* requirements for specific station and/or a specific megawatt requirement (to within an acceptable deadband). L/R must be selected such that the resulting transmission conditions do not prevent L/R actions to alleviate the system *security* concerns. L/R selections in the vicinity of a nature or man-made disaster must not hamper *emergency* measures.

   (ii) **Trip History.** L/R selections should attempt to equalize the number of L/R operations for each station over the long term and minimize the exposure of any station to two successive Load Rejections.

   (iii) **Minimize Number of Stations.** The number of stations selected for rejection should be minimized.

(iv) **Area Fairness.** Where L/R may be available for selection in more than one area, the stations selected for L/R should be distributed among each participating area. This distribution should be in approximate proportion to the percentage of the total load supplied by all areas involved in the scheme.

Generation Rejection Selections

a. Generation Rejection (G/R) should be selected to satisfy the following in order of priority:

(i) **Security.** G/R requirements must satisfy system *security* requirements for specific unit selections and/or specific megawatt requirement (to within an acceptable deadband).

(ii) **Minimize Number of Units.** The number of units selected and total megawatts selected for G/R should be minimized within the constraints imposed by plant and system operating conditions.

(iii) **Trip History.** Selections should attempt to equalize the number of unit trips based on history.

b. Where the selection of G/R is used to prevent the post-contingency thermal overloading of *IESO-controlled grid* components:

(i) G/R may be selected whenever the post-contingency loading without such rejection would exceed the appropriate Limited Time Rating in the amount sufficient to respect that rating.

(ii) If the lack of fast-acting control actions combined with the complexities of post-rejection operation, will jeopardize the ability to reach long-time ratings within the appropriate “limited” time, then rejection of sufficient generation to prevent loading beyond the long-time ratings will be permitted.

c. Ideally, sufficient generation should be selected for rejection to observe operating *security limits* so that manual corrective measures can be avoided, following a G/R operation, when attempting to achieve a minimum level of *IESO-controlled grid security*.

d. G/R selections should be made, to the extent practicable, to address any *market participant facility* concerns, such as:

(i) maximum number of units selected within a single *control center*,

(ii) the minimum number of unselected generating units, and

(iii) unavailability or preferences of specific units for G/R selection.

e. The Bruce *SPS* is limited to 2 unit arming and no load rejection is permitted.

Generation Runback Selections

a. All policies in place for G/R apply equally to Generation Runback.

– End of Section –

References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_PRO_0016	Market Manual 1: Market Entry, Maintenance & Exit, Part 1.2: Facility Registration, Maintenance and De-registration
MDP_PRO_0024	Market Manual 2: Market Administration, Part 2.8: Reliability Assessments Information Requirements
IMP_MAN_0012	Market Manual 7: System Operations, Part 7.0: Systems Operations Overview
MDP_PRO_0040	Market Manual 7: Systems Operations, Part 7.1: Systems Operating Procedure
IMP_PRO_0033	Market Manual 7: System Operations, Part 7.2: Near-Term Assessments and Reports
IMP_GOT_0002	Market Manual 7: System Operations, Part 7.6: Glossary of Standard Operating Terms
IESO_PRO_0874	Market Manual 11: Reliability Compliance, Part 11.2: Ontario Reliability Compliance Program

– End of Document –