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POLICY

Market Manual 7: System Operations

Market Manual 7.4: IESO-Controlled Grid Operating Policies

Issue 40.0

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

Disclaimer

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Related Documents

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MDP_PRO_0040	Market Manual 7.1: IESO-Controlled Grid Operating Procedures

(**This page must be removed before the document is released to the public. This section is only pertinent to *IESO*, not the public. **)

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Reference (Section and Paragraph)	Description of Change
Throughout	Added to include electricity storage participation where required.

Market Manuals

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

Market Policies

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

– End of Section –

1. Introduction

1.1 Purpose

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

- Provide guidance for the development of *IESO* procedures,
- Provide guidance to *IESO* operating staff when confronted with an operational situation that is not addressed in an operating procedure or a *market rule,* and
- Help *market participants* meet their obligations to the *IESO* in the operating time horizon*.*

To the extent practicable, the *IESO* will use available market mechanisms to direct reliable operation of the *IESO-controlled grid*. Where the *IESO* determines such mechanisms are unable to achieve reliable operation, it will take actions in accordance with the policies contained in this *market manual*.

1.2 Hierarchy

Operating policies shall conform to the *Electricity Act 1998, market rules*, *NERC reliability standards* and *NPCC* directories. When the interpretation of an *IESO* operating policy is in question, *IESO* staff shall select the interpretation most consistent with the *market rules*. When the proper interpretation of a *NERC* standard is in question, *IESO* staff shall select the interpretation most consistent with the purpose of the standard and NERC's objects to maintain the minimum level of reliability. When the proper interpretation of *NPCC* criteria is in question, *IESO* staff shall select the interpretation most consistent with NPCC's reliability objects.

The operating policies of this manual are built on the foundation that Ontario's power system is planned and designed in accordance with the *Ontario Resource and Transmission Assessment Criteria (ORTAC)*. Where existing equipment is insufficient to satisfy *ORTAC* criteria, special practices shall be documented in operating instructions and followed until the required equipment is in operation.

In case of a discrepancy between this *market manual* and another *manual* in the *Market Manual* 7 series, the policies of this *market manual* shall apply. In case of discrepancy between this document and a more stringent *reliability standard*, the *reliability standard* shall apply.

1.3 Scope

These policies apply to the *IESO* in its role to fulfill its legislated objects to direct the operation and maintain the *reliability* of *IESO-controlled grid* and to establish and enforce criteria and standards related to the reliability of the *integrated power system*.

Operating policies will be applied to *facilities* connected to the *IESO-controlled grid*.

Procedural details necessary to implement these policies are outside of the scope of this document. These details shall be found in the applicable *market manual* of the M*arket Manual* 7 series.

1.4 Roles and Responsibilities

1.4.1 Principles

The responsibility for directing the operation and maintaining the *reliability* of the *IESO-controlled grid* is assigned to the *IESO* in the *Electricity Act, 1998,* Section 6(c) and in *Market Rule* Chapter 5, Section 3.2, (MR Ch. 5 Sec. 3.2) and is a condition of the *IESO License*. The *IESO* develops and maintains the policies and procedures necessary to meet this responsibility as well as monitor and enforce compliance with applicable *reliability standards.*

The *IESO* directs its operation within the framework of the *market rules, market manuals, operating agreements*, *interconnection agreements* and other operating documentation.

The *IESO* recognizes the authority of a *market participant* to take independent action to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*.

1.4.2 IESO Responsibilities

IESO staff must adhere to the policies defined in this document when operating the *IESO-controlled grid*. Staff will:

- Take all material actions required to maintain at least the minimum acceptable level of *reliability*. The minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition limits.
- Establish and interpret *System Operating Limits (SOLs)* and verify their accuracy
- Identify operating conditions (e.g., High Risk, Normal, *Emergency*, etc.) under which a particular *SOL* will be implemented.

The *IESO* is responsible for maintaining the *reliability* of the *IESO-controlled grid* and to achieve this efficiently through *the IESO-administered markets*. To the extent necessary to maintain *reliability*, the *IESO* shall intervene in *IESO-administered markets*. For example, the *IESO* will produce *SOLs* that accurately reflect a studied operating state. However, when reacting to an unstudied operating state, the *IESO* will give precedence to system *security* over market efficiency (e.g., by formulating *SOLs* on a conservative basis until time permits more detailed assessments).

1.5 Document Layout

The *IESO* is primarily responsible for system *security* and *adequacy*.

Adequacy	The ability of the power system to supply the electrical *demand* on the system, taking into account scheduled and reasonably expected unscheduled *outages* of system elements.
System security	The ability of the power system to withstand sudden disturbances or unanticipated loss of elements.

Section 2: Reliability covers policies that affect both system *security* and *adequacy.*

Section 3: Adequacy covers policies that ensure an **adequate** system.

Section 4: System Security covers policies that ensure a **secure** system.

1.6 Contact Information

Changes to this public *market manual* are managed via the *IESO* Change Management process. Stakeholders are encouraged to participate in the evolution of this *market manual* via this process.

To contact the *IESO*, you can email *IESO* Customer Relations at customer.relations@ieso.ca or use telephone or mail. Telephone numbers and the mailing address can be found on the IESO website (IESO corporate contact information). Customer Relations staff will respond as soon as possible.

– End of Section –

2. Reliability

2.1 Principles

The *IESO-controlled grid* shall operate at a level of *reliability* such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of *reliability* is achieved by operating the *IESO-controlled grid* to meet *adequacy* criteria for anticipated *demand*, system *security* criteria for specified contingencies, and re-preparation criteria for restoring *reliability* following contingencies.

2.2 Communications

2.2.1 Policies

IESO communication procedures shall comply with *NERC reliability standards* and *NPCC* directories related to communications. *IESO* requirements for communications are published in [*Market Manual* 7.1: System Operations Procedures].

2.3 Outage Management

2.3.1 Principles

When assessing proposed *outages* of *market participant registered facilities* and associated equipment, the *IESO* shall base outage approval solely on maintaining reliable operation (including overall *adequacy* and operability) of the *IESO-controlled grid* (MR Ch. 5 Sec. 6.2 – 6.4B). The *IESO* shall reject, revoke, or recall an *outage* if it presents a *risk* to the reliable operation of the *IESO-controlled grid*.

Reliability standards do not impose an absolute requirement to maintain a continuous supply of electricity to any specific customer.

2.3.2 Policy

The *IESO* shall deal fairly and appropriately with *market participants,* and comply with the applicable *market rules* and *market manuals*. The *IESO* will provide *market participants* with timely and accurate information regarding the *IESO-controlled grid* to facilitate *market participant* coordination of *outages* and provide mechanisms to resolve *outage* conflicts.

The *IESO* shall coordinate *outages* to equipment external to Ontario with authorities in neighbouring jurisdictions to meet *NERC* and *NPCC* obligations, and to satisfy *IESO operating agreements* with interconnected neighbours. The *IESO* will NOT coordinate *outages* to individual customer connections. This obligation rests with the associated *transmitter.*

For switching configurations expected to last not more than 15 minutes, the only system *security* criteria that will be observed are:

- Equipment loading shall be within pre-contingency ratings supplied by asset owners, and

- Transfers shall be restricted to prevent pre-contingency voltage collapse.

The *IESO publishes* and maintains a *market manual* for *outage management* of *facilitie*s and equipment connected to the *IESO-controlled grid*, or which may affect the operation of *the IESO-controlled grid*. Refer to Market Manual 7.3: Outage Management.

2.4 Grid Operating States

2.4.1 Principles

The *IESO* operates under a set of grid operating states based on system conditions and the *IESO's* ability to monitor the *ICG*. The *IESO-controlled grid* has four operating states~~system *security*~~*:* the ~~*emergency operating state*, the~~ *normal operating state,* the *conservative operating state*, the *high-risk operating state* (including safe posture), *and the emergency operating state*~~,~~. In addition to the operating states, there is~~such as~~ system restoration (Section 4.5), which occurs~~s~~ immediately following a contingency that results in loss of load, cascading outages, islanding, etc.

Under certain operating conditions (e.g., adverse weather or equipment-related problems), the probability of experiencing certain contingencies ~~(or the severity of associated consequences)~~ increases. The *IESO* shall temporarily and selectively increase the level of system *security* to improve *reliability* during a~~these~~ *high risk operating state*~~*s*~~.

Under ~~other~~stressed conditions (e.g., extreme hot or cold temperatures, anticipating energy or capacity deficiencies, or outages to *IESO* market or system applications ~~or tools~~ that impact ~~the~~ system *security*), the *IESO* will seek to minimize potential risks to the *ICG* or enhance grid resiliency in anticipation of (and after the declaration of) a *conservative operating state*. Th~~is~~e *conservative operating state* ~~will be one of the control actions~~is available to the *IESO* ~~to be taken in response to a reliability concern and~~ to help prevent an *emergency operating state.*

Under ~~other~~ critical conditions (e.g., ~~anticipating or~~ experiencing *energy* ~~deficiencies~~ or capacity deficiencies, or ~~operating in an unstudied operating state~~*security* emergency), *non-dispatchable load* shedding may be required. The *IESO* strives to mitigate or avoid *non-dispatchable load* shedding when in these *emergency operating states* by ~~publishing and~~ maintaining a ~~hierarchy~~ variety of control actions to be taken in anticipation of (and after the declaration of) an *emergency operating state*. Refer to the Emergency Operating State Control Actions (EOSCA) list in Market Manual 7.1: IESO-Controlled Grid Operations Procedures, Appendix B.

In high-risk, conservative, and *emergency operating states*, *IESO* control actions to maintain system *security* are more likely to be taken ~~than~~compared to during a *normal operating state. These actions are* structured to:

1. Preserve system *reliability.*
2. Restore normal operation of *IESO-administered markets* as soon as practicable (*MR* Ch 5, Sec. 7.7.2).

The *IESO* will strive to mitigate adverse effects on *IESO-administered markets*, while at the same time observing the mutual protection and assistance provisions contained in agreements between the *IESO* and other *reliability coordinators* and *balancing authorities.*

2.4.2 High-Risk Operating State

In a *high-risk operating state*, the *IESO* will temporarily and selectively increase the level of *system security* by applying high-risk operating limits. The *IESO* will take actions such as rejection, revocation, or recall of equipment and *facility outages* when necessary to:

- Maintain the level of system *security* required during a *high-risk operating state*, and
- Allow, after a recognized contingency, the *IESO* to re-establish an acceptable level of system *security* and to re-prepare the *IESO-controlled grid* within the time permitted by *reliability standards*.

The conditions under which a *high-risk operating state* may be declared (along with related policy implementation details) can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.4.3 Conservative Operating State

The *IESO-controlled grid* can be operated in a *conservative operating state* in response to a reliability concern to help prevent an *emergency operating state*. In a *conservative operating state*, the *IESO* may reject, suspend, or revoke equipment and *facility outages* to minimize any potential risks to the *IESO-controlled grid* that could occur from non-urgent/routine work or switching of equipment. The *IESO* may also take actions to commit additional resources or recall equipment and facility outages to enhance grid resiliency. Under a *conservative operating state* the *IESO-controlled grid* will be operated within equipment and security limits established for a normal operating state.

For IT-related outages related to the *IESO-administered markets* and/or system applications or tools that affect system *security*, the *IESO* may also take actions such as requesting MPs or neighbouring *control area operators* to monitor the *IESO-controlled grid* or the interties, respectively, on behalf of the *IESO*. In addition, *market participants* may need to implement manual workarounds to fulfill their obligations (e.g., receive and execute verbal dispatch instructions).

The conditions under which a *conservative operating state* may be declared can be found in Market Manual 7.1: IESO-Controlled Grid Operating Procedures.

~~2.4.3~~2.4.4 Normal Operating State

In a *normal operating state,* the *IESO* will supply all *non-dispatchable loads* while operating to normal condition limits.

The *IESO* shall direct *market participants* to act or to refrain from acting so as to maintain the *IESO-controlled grid* in a *normal operating state* (MR Ch. 5 Sec. 2.2). The *IESO* will also act or refrain from acting where doing otherwise is likely to lead to a *high-risk* ~~-~~or *emergency operating state* (MR Ch. 5 Sec. 2.3.2, 2.4.2, and 5.1.2.6).

~~2.4.4~~2.4.5 Emergency Operating State

The *IESO* shall not plan to operate the *IESO-controlled grid* in an *emergency operating state* pre-contingency, including when considering *planned outages*.

The *IESO* strives to mitigate or avoid *non-dispatchable load* shedding when in an *emergency operating state* by publishing and maintaining a hierarchy of control actions to be taken in anticipation of and after the declaration of an *emergency operating state* (refer to the EOSCA list in *Market Manual 7.1*).

Temporarily and selectively reducing the level of system *security* by applying emergency condition operating limits is one of the many control actions the *IESO* can take when in an *emergency operating state*.

At all times, the minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load* in accordance with Section 2.7.8, to observe the emergency condition operating limits.

An *emergency operating state* will generally not be declared when normal or routine control actions can resolve the capacity or *energy* deficiency, or return the *IESO-controlled grid* to a studied operating state in a timely manner. Implementation details, including the conditions under which an *emergency operating state* may be declared can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.5 Degraded Transmission Equipment Performance

A higher than long-term average *forced outage* rate, unanticipated tripping, or unanticipated failure to trip are typical examples of degraded transmission equipment performance. Where transmission equipment has shown degraded performance, or if degraded performance is anticipated, the *IESO* shall take control actions such as the following:

- Reschedule routine maintenance work, except work to remedy degraded performance,
- Reject or revoke any *planned outages* with Planned, Opportunity, or Information Priority Code anticipated to have an adverse impact on the *IESO-controlled grid,* except for *planned outages* to remedy degraded performance*,*
- Recall any *planned outages* with Planned, Opportunity, or Information Priority Code that may have an adverse impact on the *IESO-controlled grid* associated with the affected portion of the *transmission system,*
- Request staffing at transmission stations during periods of routine switching, during periods of high risk of equipment operation, or on a 24/7 basis depending on the severity of equipment degradation,
- Adjust *IESO system security* assessments to account for additional elements anticipated to be removed from service due to equipment degradation,
- Adjust use of *Remedial Action Schemes* to reduce operation of affected *transmission system* equipment, or
- Direct *generators* and other *market participants* as required to enhance *reliability.*

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

2.6 Islanding

The *IESO* shall notify *generators* and *electricity storage participants* of *outages* that would put their units in an electrical island following a single element contingency to inform their operating decisions.

The *IESO* shall NOT manually constrain down resources pre-contingency in order to assist a rapid collapse of an electrical island. When determining whether an island will survive or collapse, the *IESO* shall assume that inverter-based generation (i.e., wind and solar) will immediately trip in an electrical island where conventional synchronous units cannot meet *demand* in the island.

The *IESO* shall NOT manually constrain up resources pre-contingency in order to assist the survival of an electrical island.

The *IESO* shall take available pre-contingency control actions (other than constraining resources, such as a configuration change or *RAS* arming) to assist the rapid collapse of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will not be controlled within acceptable ranges, **or**
- *IESO* cannot obtain voltage and frequency measurements in the island.

The *IESO* shall take available pre-contingency control actions (other than constraining resources, such as a configuration change or *RAS* arming) to assist the survival of an electrical island formed by a single element contingency if:

- *IESO* studies pre-determine that voltage and frequency will be controlled within acceptable ranges, **and**
- *IESO* can obtain voltage and frequency measurements in the island.

The *IESO* shall synchronize islands only by using breakers that have synchrocheck relays, or a mechanism of ensuring that the circuit breaker closes only if voltages on both sides of the circuit breaker fulfill conditions of magnitude, phase, and slip frequency.

If special islanding practices are developed that differ from the above general policy, these practices shall be documented in operating instructions.

2.7 Grid Control Actions

2.7.1 Principles

The objective of the *IESO-administered markets* is to promote an efficient, competitive, and reliable market for the wholesale purchase and sale of electricity and *ancillary services* in Ontario (MR Ch. 1 Sec. 3.1.1).

To satisfy this objective, all practicable control actions shall be taken to move towards an unconstrained *dispatch* while observing all system *security* or *adequacy* constraints.

2.7.2 Readiness Programs

To maintain confidence that control actions will be available when called upon (MR Ch. 5 Sec. 4.6.2), the *IESO* shall test or require *market participants* to test *facilities* that are connected to the *IESO-controlled grid*. This testing could be to prepare for the next peak season, or to prepare for extreme conditions that are expected in the next few days. For example, voltage reduction, *operating reserve* activation, and reactive capability will be periodically tested.

IESO readiness program implementation details can be found in *Market Manual* 7.1: IESO-Controlled Grid Operating Procedures.

2.7.3 Network Configuration Change Request

The *IESO* shall assess proposed network configuration requests to manage individual *delivery point* performance and, through the *outage* management process, approve proposals that do not:

- Degrade the *reliability* of the *IESO-controlled grid*,
- Reduce an SOL or transfer capability,
- Result in inconsistent application of established system *security* criteria and *reliability standards*,
- Impose additional exposure to loss of essential *station service* supply to nuclear generating stations,
- Expose the *IESO-controlled grid* to additional contingencies that have a material adverse effect on the *reliability* of the *IESO-controlled grid*,
- Impose additional risk/restrictions related to post-contingency response to recognized contingencies, and
- Interfere with the operation of *IESO-administered markets* (i.e., do not result in changes in generation *dispatch*, *market clearing price,* or congestion payments).

During normal situations, the *IESO* will include such advance-approved proposals in its operating instructions ahead of real-time operations.

During abnormal situations (e.g., *forced outages*, responding to contingencies, system restorations, etc.), the *IESO* may deviate from the above provisions while respecting their intent to the extent possible.

2.7.4 Control Actions to Increase Transfer Capability

To increase transfer capability to improve *reliability* and/or reduce congestion costs, the *IESO* will assess and may implement control actions such as:

- Changing reactive *dispatch*,
- Changing transformer winding or phase angle taps,
- Load transfers,
- Arming *remedial action schemes (RASs)*,
- Manually constraining generation and electricity storage up or down,
- Opening breakers or switches, including high or low voltage bus tie breakers,
- Taking equipment off load, or
- Removing equipment from service.

The applicable *transmitter* must concur with a control action that will reduce connection redundancy, or transfer load where *delivery point* performance is substandard.

The *IESO* will implement these control actions, or include them as part of its operational planning assessment of *outage* requests, unless the action:

- Fails to conform to a policy contained in this document,
- Exposes nuclear generating stations to loss of essential *station service* supply following an Appendix A, Group 1 contingency, or
- Causes post-contingency configurations expected to exceed system *security* restoration timelines.

2.7.5 Voltage Control

To maintain transmission line voltages within ranges, to respect *SOLs,* and to respect equipment ratings, the *IESO* will *dispatch* the following:

- *Generation unit* and *electricity storage unit* reactive power within unit capability,
- Reactive control devices subject to *operating agreements*, and
- Reactive control devices subject to procurement contracts.

The *IESO* will *dispatch* the following to meet *connected wholesale customer* or *distributor* voltage needs, as long as these actions do not exceed *SOLs* and equipment ratings:

- *Generation unit* and *electricity storage unit* reactive power within unit capability, and
- Reactive control devices subject to *operating agreements*.

2.7.6 Remedial Action Schemes

The *IESO-controlled grid* system *security* must be returned to a secure state within times prescribed by *reliability standards* following operation of a *RAS*. The IESO will direct the use of RAS as outlined in *transmitter operating agreements*.

A *RAS* shall not be deployed until it has been classified in the *NPCC* process as Type I, II, or III. A Type I *RAS* shall be deployed in a manner consistent with its description in the *NPCC* approval process. Usually a Type I RAS is approved for deployment for *outage* conditions, for extreme contingencies, or for unanticipated operating conditions. Usually a Type II or Type III *RAS* is approved with fewer or no deployment restrictions.

Specific criteria for selection of load rejection (L/R), generation rejection (G/R), and generation runback are contained in Appendix B. The use of a *RAS* during a *high-risk operating state* shall be subject to the restrictions contained in Appendix C.

The *IESO* shall allow *market participants* to request an exclusion from L/R for the following reasons:

- Public safety hazard,
- Potential damage to equipment,
- Potential violation of any *applicable law*,
- Outages to equipment directly associated with L/R tripping or restoration, or
- Outages to equipment which may degrade the integrity of L/R tripping or restoration (such as, but not limited to, relaying or station supervisory control equipment).

The *IESO* shall direct the restoration of rejected load. Load may be restored following rejection by interrupting other load (i.e., rotating blackout) as a substitute.

2.7.7 Voltage Reductions

The *IESO* may direct a *market participant* to initiate voltage reductions to prevent or to mitigate an *emergency operating state* (MR Ch. 5 Sec. 10.1.1) resulting from events including:

- Equipment thermal overloads,
- Insufficient *generation capacity* and *electricity storage* injection capacity to satisfy non-dispatchable demand,
- Violations of high-risk, normal, or emergency SOLs, or

- An event requiring the *IESO* to activate *operating reserve* that is provided by *voltage reductions*.

2.7.8 Non-Dispatchable Load Shedding

Shedding *non-dispatchable load* is a permissible *IESO* control action to maintain grid integrity, or to respect safety, equipment, or *applicable law* constraints.

When an *SOL* is exceeded, *non-dispatchable load* shedding may be avoided or deferred by taking the following steps as required:

1) **Disregard high-risk limits and apply normal limits.**

   This step will allow an increase in transfer limits constrained by *RAS* arming restrictions and other restrictions due to a *high risk operating state*.

2) **Disregard normal limits and apply emergency condition operating limits.**

   This step will allow an increase in transfer limits constrained by contingencies involving more than one element.

The *IESO* shall shed load during an *emergency operating state* under the following conditions:

- To alleviate a capacity or *energy* emergency,
- To alleviate or avoid exceeding pre- and post-contingency equipment ratings,
- To alleviate or avoid exceeding a pre-contingency voltage collapse, or a steady-state instability, or
- To alleviate or avoid exceeding an Interconnection Reliability Operating Limit (IROL) or Bulk Power System (BPS) limit.

Note that when a transfer is near its limit, both the limit and its associated boundary conditions (e.g., minimum voltage at Longwood, Bruce, etc.) are equally important considerations. As a transfer departs from its limit, boundary conditions become less important, and it may not be necessary to shed *non-dispatchable load* to address a boundary condition exceedance. Discretion to avoid shedding *non-dispatchable load* for a boundary condition exceedance is documented in operating instructions.

When an *emergency operating state* has been declared and reduction in *demand* is required to safeguard the *reliability* of the *IESO-controlled grid*, the *IESO* shall direct manual load shedding to reduce *demand* on the following basis:

- Priority customer loads (refer to [*Market Manual* 7.10: Ontario Electricity Emergency Plan]) such as hospitals and water treatment plants without backup *generators*, and electrically driven gas compressors should be avoided when determining what load to shed.
- The amount and location of load to be cut will be selected to solve the operating problem to maintain an adequate level of *IESO-controlled grid adequacy* or system *security*.
- When time permits, load cuts via manual rotational load shedding schemes should be spread equitably across the *IESO-controlled grid* to the extent practicable. Equitable considerations will include magnitude, duration, and frequency of load reductions.

– End of Section –

3. Adequacy

3.1 Principles

The *IESO* shall maintain an adequate supply of generation and transmission to meet forecast Ontario *demand* in the operational timeframe. When assessing generation and transmission *adequacy*, the *IESO* will consider factors including the following:

- *Demand* forecast,
- *Variable generation* (e.g., wind and solar) forecast,
- Load forecast uncertainty,
- Additional contingency allowance,
- *Operating reserve* requirements,
- Generation, electricity storage and *demand response* availability forecast, which includes the available but not operating (ABNO) units, and generation external to Ontario and associated tie-line capability,
- Transmission *facility* capability forecast,
- Applicable *SOLs*, and
- Acceptable voltage ranges.

3.2 Resource and Transmission Adequacy

When assessing *adequacy*, the *IESO* shall compare forecasted *demand* to available resource capacity and *energy*, including available resources external to Ontario. The *IESO* shall assess *adequacy* for *normal operating states* on a daily basis in its short-term operating assessments, on a weekly basis in its medium-term assessments, and on a less frequent basis in longer-term assessments. For these operating horizons, criteria to identify an acceptable level of *adequacy* (and corrective actions if this level cannot be achieved), can be found in Market Manual 7.2: Near-Term Assessments and Reports.

When assessing transmission *adequacy*, the *IESO* shall compare transmission flow forecasts with the applicable *SOLs* under an anticipated range of power system conditions. Transmission is adequate if *demand* forecasts can be supplied without exceeding applicable *SOLs*, and acceptable system voltages can be maintained.

3.3 Operating Reserve Policy

Operating Reserve shall be scheduled (MR Ch. 5 Sec. 4.5.1) to ensure resources are available to:

- Cover or offset unanticipated increases in *demand* during a *dispatch day* or *dispatch hour*,
- Cover or offset capacity lost due to a *forced* or urgent *outages* of generation, injecting *electricity storage facilities*, or transmission equipment, or
- Cover uncertainty associated with the performance of *generation facilities, electricity storage facilities,* or *dispatchable loads* in responding to *IESO dispatch* instructions.

Additional reserve shall be carried to account for an increased risk of tripping during commissioning tests. No additional *operating reserve* shall be required during a commissioning period when no tests are scheduled that materially increase the risk of unit tripping.

Operating reserve shall be scheduled in sufficient quantity and shall be distributed so as to ensure that it can be utilized for any single contingency that results (i) in generation loss or (ii) electricity storage injection loss, or both (i) and (ii), without exceeding equipment or *transmission system* limitations.

Voltage reduction may be used to provide *operating reserve*.

3.4 Area Reserve for Load Security

Area reserves (i.e., reserves that are scheduled or resources that are pre-committed to avoid shedding *non-dispatchable load*) shall be scheduled as follows:

- **For all *SOLs*:** All available resources shall be committed to avoid shedding *non-dispatchable load* before a contingency.
- **For IROLs and BPS parts of the system:** Non-energy limited resources shall be pre-committed so that following a single-element contingency, the system can be re-prepared within 30 minutes to operate to IROL and BPS emergency contingency limits, without shedding *non-dispatchable load*.
- From time to time, the *IESO* may choose to carry additional area reserve beyond those required here for circumstances such as extreme weather forecasts, physical *security* threats, etc.

– End of Section –

4. System Security

4.1 Principles

This section describes the level of system *security* that must be achieved so that the risk of loss or separation of major portion of the *interconnected system* is reduced to an acceptable level.

The *IESO-controlled grid* must display satisfactory performance before and after *contingency events*. All *IESO* performance criteria must be satisfied, not only the transient and voltage stability criteria, for an operating condition to be deemed stable.

The *IESO-controlled grid* must be operated such that in a normal, planned state, voltages will be within normal limits, equipment loading will be within continuous ratings as supplied by *facility* owners, and transfers will be within *SOLs*. For *planned outages* with Planned, Opportunity, or Information Priority Code, equipment may be loaded to long-term *emergency* ratings pre-contingency if authorized by the facility owner. Operation within authorized ratings shall be considered sufficient to avoid physical damage, protect safety, and avoid violation of any *applicable law* unless otherwise notified.

The *IESO* will use the following policies to develop operational plans, establish *SOLs* and instructions, and operate the *IESO-controlled grid*.

4.2 Methodology for Deriving System Operating Limits

SOLs shall be established[1] by monitoring the system security criteria in Section 4.3 on Bulk Power System (BPS), Bulk Electric System (BES), and Local elements in the following manner:

1. On BPS elements, the system security criteria shall be satisfied for any Appendix A Group 1 contingency occurring on the BPS. If the *IESO* becomes aware of an Appendix A Group 1 contingency not on the BPS that results in a significant adverse impact to the BPS**,** the *IESO* must operate the system to respect that event. As Group 1 includes multiple element contingencies, this fulfills requirement R3.3 of *NERC* standard FAC-011. The monitoring of all Group 1 contingencies in Ontario on BPS elements satisfies *NPCC* Directory #1 R13.
2. On BES elements, the system *security* criteria shall be satisfied for any Appendix A Group 2 contingency occurring anywhere in Ontario.
3. On Local elements, the system *security* criteria shall be satisfied for any Appendix A Group 3 contingency occurring anywhere in Ontario.
4. BPS elements, only for the purposes of *SOLs*[2], are determined in the following manner:
    a. Start with all elements identified in accordance with *NPCC's* A-10 test performed on a set of system conditions that covers the range of anticipated operation.

[1] The *IESO* derives voltage change and stability limits, and monitors thermal limits based on ratings provided by asset owners.

[2] This section does not concern itself with other uses of BPS for *NPCC* Directory 4 applications for protections.

   b. Add elements as necessary when operating conditions are more onerous than those studied in (a).
   c. Remove elements that do not affect neighbouring jurisdictions. Where there is an effect, the *IESO* must obtain concurrence from affected neighbouring jurisdictions before removing the element.
5. BES elements are determined in accordance with *NERC's* BES definition.
6. Local elements are the remainder after BPS and BES elements have been determined.

The *IESO* will classify the *SOLs* derived using the methodology as noted in points 1 to 3, above, as *IROLs* based on studied impacts on neighbouring jurisdictions. Where there is an effect, IESO will obtain concurrence from affected the neighbouring Reliability Coordinator(s*)*, before removing the *IROL* designation.

If the IESO becomes aware of a contingency outside Ontario that materially affects the *IESO-controlled grid,* the *IESO* will observe the impact of that contingency on *IESO-controlled grid* in the same manner as contingencies within the *IESO-controlled grid*.

A neighbouring jurisdiction will determine the criteria for assessing effects of contingencies within the *IESO-controlled grid* on their system.

4.3 System Security and Modelling Criteria

4.3.1 Principles

The derivation of *SOLs* shall be done in accordance with the system *security* and modelling criteria described in the following sections.

4.3.2 Study Conditions and System Model

The study conditions used shall cover expected operating conditions (e.g., generation *dispatch* and load levels), and shall reflect changes to system topology (e.g., *facility outages*).

The study model for determining *SOLs* must include at least the entire Reliability Coordinator area, as well as the critical modelling details from other Reliability Coordinator areas that would impact the *facility* or *facilities* under study.

The study model must contain a sufficient amount of detail, including representation of the physical and control characteristics of modelled *facilities*, to ensure fulfillment of the *IESO's* mandate to operate *IESO-controlled grid* reliably.

4.3.3 Load Representation

Constant megavolt-amp (MVA) load models shall be used to assess a pre-contingency state.

Voltage-dependent load models may be used to assess a post-contingency state before and after tap-changer action. The default voltage-dependent load model shall be used unless a different model has been approved by the *IESO*. The default voltage dependant for active (P) and reactive (Q) load shall be defined as follows:

$$P(V) = 0.5 \times P_0 \times \frac{V}{V_0} + 0.5 \times P_0 \times \left(\frac{V}{V_0}\right)^2$$

$Q(V) = Q_0 \times \left(\frac{V}{V_0}\right)^2$ V_0 P_0, Q_0 are pre-contingency values

In areas where representation of load is critical, such as areas with a material amount of motor load, a detail representation of transient load behaviour should be attempted.

4.3.4 Thermal Rating Policy

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of thermal ratings for such equipment as communicated to the *IESO* by relevant *market participants*. When a critical adverse effect is not apparent to *market participants*, such as a backfeed arising from a recognized contingency at a remote location on the *IESO-controlled grid*, the *IESO* shall take actions to avoid exceeding thermal ratings. When a critical adverse effect is apparent to a *market participant* and they have control, such as loading of *generator* step-up or DESN transformers, the *market participant* shall take action to avoid exceeding thermal ratings.

Limited time ratings shall be utilized only if control actions are available to reduce loading to a longer time rating within the interval afforded by a limited time rating. For example, a 15-minute rating may only be utilized if control actions are available to reduce loading to a longer term rating (e.g., a 10-day rating) within 15 minutes. Post-contingency loading shall not exceed the shortest applicable limited time rating.

The scope of thermal monitoring will be established in *operating agreements* between *IESO* and *transmitters*.

4.3.5 Pre-contingency Voltage Range

The *IESO-controlled grid* shall be operated in the voltage ranges shown in Table 4-1 under pre-contingency conditions and following re-preparation unless affected equipment owners have agreed to a wider range.

For transmission voltages, the values are from Chapter 4 of the *market rules*. For distribution voltages, the values are based on Canadian Standards Association (CSA) Standard 235.

Table 4-1: Pre-Contingency Voltage Limits

Nominal Bus Voltage	Transmission Stations			Transformer Station (Load Facility) Low Voltage at 44 kV, 27.6 kV, 13.8 kV
	500 kV	230 kV	115 kV	
Maximum Continuous	550 kV	250kV	127 kV*	106% of nominal
Minimum Continuous	490 kV	220 kV	113 kV	98% of nominal

* In portions of northern Ontario, the *maximum continuous* voltage for the 115kV system can be as high as 138 kV.

Exceptions to maximum and minimum voltages must be documented in relevant operating instructions.

4.3.6 Post-contingency Voltage Change Limits

Transmission system voltage changes following recognized contingencies (i.e., after the contingency has been cleared) shall be limited as shown in Table 4-2, unless the equipment owner has agreed to a wider voltage change limit. Voltage declines are intended to ensure power quality, and therefore are assessed at the high voltage terminals of stations with load other than *station service* load. Voltage rises are assessed at all of the buses mentioned in the table. Operating instructions must document exceptions to voltage change limits, for example voltage rise restrictions due to equipment limitations, employed in *SOL* derivation.

Table 4-2: Post-Contingency Voltage Change Limits

Transmission Bus Designation	Operating Condition	Contingency Type	Change Before Tap Changer Action	Change After Tap Changer Action
BPS	Normal	Single-element	5%	10%
BPS	Normal	Double-element	10%	15%
BPS	Emergency	Single-element	10%	15%
BES and Local	All	Single-element	10%	15%

4.3.7 Voltage Stability

Voltage stability for power transfers for all anticipated operating states shall be demonstrated using power-voltage (PV) analysis accordingly:

- A power transfer corresponding to Point 'A', which if increased by 10%, is less than the power at the critical point of the pre-contingency PV curve, and
- A power transfer corresponding to Point 'B', which if increased by 10%, is less than the power at the critical point of the post-contingency PV curve.

When producing a pre-contingency PV curve, manual actions such as reactive shunt switching together with transformer tap-changer action, are permitted. When producing a post-contingency PV curve, only automatic control actions (e.g., generation *automatic voltage regulation*, *RASs*, and automatic under-load tap-changes) shall be modelled.

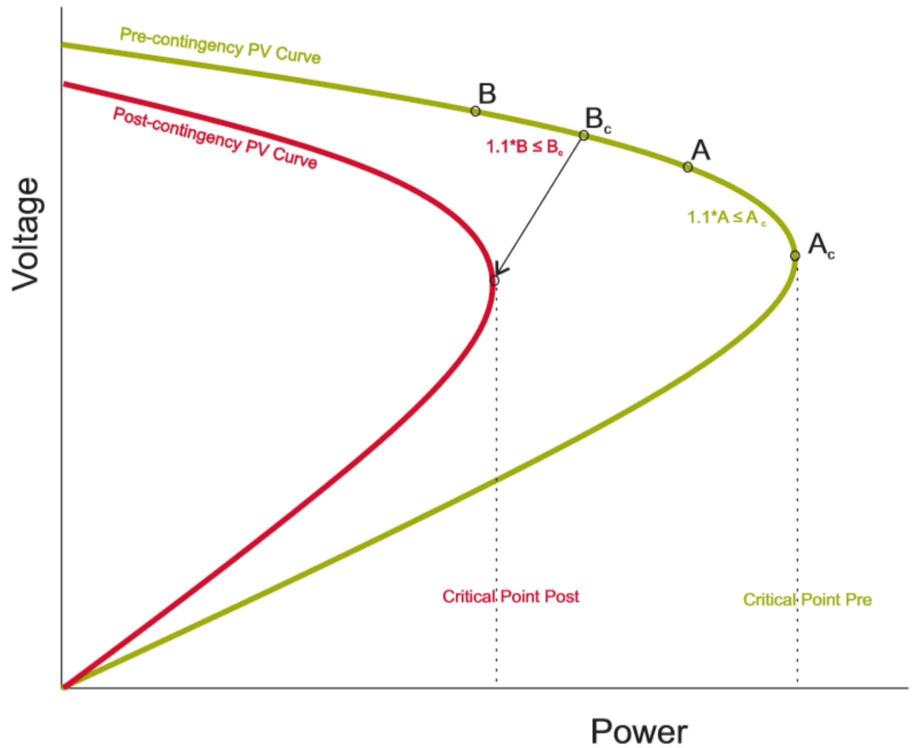

Figure 4-1: Typical PV Curves

4.3.8 Transient Stability

For acceptable transient rotor angle stability, synchronous units remaining connected to *IESO-controlled grid* shall not lose synchronism for the applicable contingencies in Appendix A with due regard to reclosure. Transient angle stability shall be maintained if the critical parameter is increased by 10% to allow margin.

The 10% increase in the critical parameter can be simulated by generation or load changes beyond the forecast load or generation capabilities even after eliminating *station service* load. Conditions at margin shall be as realistic as reasonably achievable. The use of negative values of local load is preferable to increasing local generation beyond its maximum capability. Negative load used for margin must have a constant MVA characteristic.

Design operating times of fault detectors, auxiliary relays, trip modules, communication media, breakers, etc., may be used for calculating switching times when reliable field-measured data are not available.

4.3.9 Small Signal Stability

The required damping factors at various conditions on the *IESO-controlled grid* are tabulated in Table 4-3.

Table 4-3: Acceptable Damping Factors

System Condition	Damping Factor
Pre-contingency	> 0.03
Post-contingency: Before any automatic *response*	> 0.00

System Condition	Damping Factor
Post-contingency: After automatic *responses*, before manual system adjustments	> 0.01
Following re-preparation of the system: After system adjustments	> 0.03

For swings characterized by a single dominant mode of oscillation, the damping may be calculated directly from the oscillation envelope.

For a damping factor of 0.03, the magnitude of oscillations must be reduced to 39% of initial values within 5 periods. For a damping factor of 0.01, the magnitude of oscillations must be reduced to 39% of initial values within 15 periods. For swings not characterized by a single dominant mode, then the damping factors should be derived via a more detailed modal analysis.

4.3.10 Protection Relay Margin

Following fault clearing, or the loss of an element without a fault, the margin on all instantaneous and timed distance relays at stations that are part of the BES or BPS, including *generator* loss of excitation and out-of-step relaying, must be at least 20% and 10% respectively.

The margin on all relays at local system stations, *generator* loss of excitation and out-of-step protections on small *generating units*, or those associated with transformer backup protections, must be at least 15% on all instantaneous relays, and 0% on all timed relays having a time delay setting less than or equal to 0.4 seconds. For all relays having a time delay setting greater than 0.4 seconds, the apparent impedance may enter the timed tripping characteristic, provided that there is a margin of 50% on time. For example, the apparent impedance does not remain within the tripping characteristic for a period of time greater than one-half of the relay time delay setting.

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

4.3.11 Automatic Reclosure

The *IESO* will use automatic reclosure to more quickly restore the integrity of the *IESO-controlled grid* following contingencies that are not permanent. Experience has shown many faults on the overhead transmission circuits to be temporary. Automatic reclosure for transformer, bus, or cable protection should only be approved in exceptional circumstances, as these faults are more likely to be permanent.

Automatic reclosure is comprised of two stages; re-energization from a single preferred breaker with under-voltage supervision and time delay followed by reclosing of the remaining breakers with synchrocheck supervision.

Circuits are normally automatically re-energized following a fault clearing by protection systems. Upon successful re-energization, the remaining breakers shall be automatically reclosed. Failure to automatically re-energize from the single preferred breaker is deemed to be unsuccessful reclosure. This section outlines settings and selection requirements for automatic reclosure:

Re-energization

- A faulted circuit should be automatically re-energized from a single preferred breaker with under-voltage supervision and a minimum time delay of five seconds. Automatic re-energization shall be initiated following damping of system oscillations. Stability-sensitive areas should have a nominal time delay of 10 seconds or longer to initiate automatic re-energization. Areas where studies indicate that higher speed reclosure has no material adverse effects on the system *security* of the *IESO-controlled grid*, re-energizing with a time delay of less than five seconds is permitted.

- The breaker chosen for the re-energization of the circuit shall be the one that would result in the least disruption in the event of a breaker failure upon an unsuccessful re-energization. Experience has shown there is a higher-than-average risk of breaker failure in an open-close-open sequence.
- The re-energizing breaker shall be at a terminal remote from steam turbine units. If possible, re-energizing should be initiated at a breaker at a terminal remote from *generation units*.
- Automatic re-energization time delay settings for adjacent transmission circuits on common towers are selected to mitigate the risk of re-energizing onto two faulted circuits at the same time.

Reclosing of the remaining breakers

- The remaining breakers shall automatically reclose with synchrocheck supervision. Where there is no electrically close generating station, voltage presence supervision with a nominal time delay of 0.5 seconds may be used.
- Automatic reclosing must not result in a sudden power change exceeding 0.5 per unit of its MVA rating on steam turbine *generation units* rated greater than 10 MVA. *Market participant* agreement shall be obtained prior to allowing a higher value of sudden power change.
- Automatic reclosure shall not be used to re-synchronize a *generation unit* that has separated from the *transmission system*.
- On those circuits where only high speed (i.e., less than one second) unsupervised automatic reclosure is available, it should normally be blocked.

SOLs shall be derived such that the system must successfully withstand an unsuccessful automatic re-energization (i.e., an open-close-open sequence) operation.

4.3.12 Manual Reclosure

Following an unsuccessful automatic reclosure, or an *outage*, a circuit will normally be manually re-energized from the preferred breaker used for automatic reclosure.

The *IESO-controlled grid* must be able to withstand manual energization of a faulted element without prior readjustment of generation levels, unless specific operating instructions to the contrary are provided.

Manual reclosure of the remaining breakers after energization must not result in a sudden power change exceeding 0.5 per unit of its MVA rating on steam turbine *generation units* rated greater than 10 MVA. *Market participant* agreement shall be obtained prior to allowing a higher value of sudden power change.

4.4 Frequency Regulation

Generators and *electricity storage participants* are required to be able to operate within the range of frequencies specified in *MR* Ch. 4, Appendix 4.2: Generation and Electricity Storage Facility Requirements. This appendix also specifies the required settings for speed/frequency regulation.

Market Manual 7.1: IESO-Controlled Grid Operating Procedures explains how generators and *electricity storage participants* are required to operate during abnormal system frequencies.

4.4.1 Automatic Under Frequency Load Shedding

The *IESO* shall administer an automatic under-frequency load shedding (UFLS) program to stabilize frequency. This program shall take into consideration the manner in which the *IESO-controlled grid* is likely to separate in the event of a *system disturbance*, compensation for early generation tripping, and *planned outages* with Planned, Opportunity, or Information Priority Code to UFLS equipment.

IESO requirements for the UFLS program are contained in MM 7.1. Priority customer loads (refer to *Market Manual* 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup generators, and electrically driven gas compressors should be considered by *distributors* and *connected wholesale customers* when satisfying UFLS program requirements.

4.5 Restoration of System Security

4.5.1 Principles

The *IESO* shall use all appropriate means to re-prepare the system to satisfy *SOLs* corresponding to emergency condition operating limits as soon as possible.

The *IESO* will endeavour to shorten the duration of an *emergency operating state*.

The consequences of control actions to return to a studied operating state must be both foreseen and acceptable. The intentional loss of a major portion of the system, or the intentional separation of a major portion of the system, are unacceptable consequences.

4.5.2 Policies

The minimum acceptable level of *IESO-controlled grid* system *security* is the level afforded by observance of emergency condition operating limits. All necessary steps are to be taken, including the interruption of *non-dispatchable load* in accordance with Section 2.7.8, to observe emergency condition operating limits.

The *IESO* shall use all available means to re-prepare BPS parts of the system and IROL interfaces to emergency condition operating limits within 30 minutes following any respected contingency. The 30-minute period starts following the occurrence of the contingency.

The *IESO* must have plans to re-prepare BPS parts of the system and IROL interfaces to emergency condition operating limits within 30 minutes following the occurrence of respected contingencies. Re-preparation plans shall not utilize control actions that increase *non-dispatchable load* shedding until resources have been committed in accordance with the Area Reserve criteria in Section 3.4.

The *IESO publishes* and maintains a power system restoration plan for Ontario in the event of a complete or partial blackout of the *IESO-controlled grid* (refer to *Market Manual* 7.8: Ontario Power System Restoration Plan).

– End of Section –

Appendix A: Recognized Contingencies

The types of contingencies that must be respected on elements[3] that form the BPS and BES are, at a minimum, specified by *NPCC* and *NERC* respectively. The types of contingencies that must be respected on the remaining local elements are specified by the *IESO*. The consequences of Group 1, Group 2, and Group 3 contingencies must be considered on BPS, BES, and local elements respectively; with due regard for how auxiliaries at generation and transmission stations are supplied by the *IESO-controlled grid*.

Single-element contingencies result in the clearing of a single protection zone, with the exception of inadvertent breaker opening contingencies. A single protection zone may comprise more than one element. To restore system *security*, it can be assumed that only one element was faulted, and the other elements comprised within a single protection zone can return to service. The timing of the return to service depends upon the particulars associated with the fault location. System *security* must be restored considering all elements that cannot be returned to service within 30 minutes.

When the *IESO-controlled grid* is in a *high risk operating state*, the *IESO* may operate the system to withstand contingencies more severe than those specified below for a *normal operating state*.

A.1 Group 1 – Contingencies

A.1.1 Normal Operating State

When the *IESO-controlled grid* is in a *normal operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) Simultaneous permanent single-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 single-phase-to-ground fault on any element with delayed fault clearing.

(iv) Loss of any element or circuit breaker without a fault.

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

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

(vii) The failure of a circuit breaker associated with a *RAS* to operate when required following the loss of any element or circuit breaker without a fault, or a permanent single-phase-to-ground fault (with normal fault clearing) on any element.

A.1.2 Emergency Operating State

When the *IESO-controlled grid* is in an *emergency operating state*, the Group 1 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

[3] An element is defined as *generator*, transmission circuit, transformer, shunt device, or bus section.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing

(iii) Single pole block with normal clearing in a monopolar or bipolar HVdc system.

(iv) Loss of any element or circuit breaker without a fault.

A.2 Group 2 – Contingencies

When the *IESO-controlled grid* is in a *normal* or *emergency operating state*, the Group 2 contingencies are:

(i) A permanent three-phase fault on any element with normal fault clearing.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing

(iii) Loss of any element or circuit breaker without a fault.

(iv) Single pole block with normal clearing in a monopolar or bipolar HVdc system.

A.3 Group 3 – Contingencies

When the *IESO-controlled grid* is in a *normal* or *emergency operating state*, the Group 3 contingencies are:

(i) A permanent phase-to-phase-to-ground fault on any element with normal fault clearing.

(ii) A permanent single-phase-to-ground fault on any element with normal fault clearing

(iii) Loss of any element or circuit breaker without a fault.

– End of Section –

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

Load Rejection (L/R) Selections

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

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

   (ii) **Sensitivity.** Priority customer loads (refer to *Market Manual* 7.10: Ontario Electricity Emergency Plan) such as hospitals and water treatment plants without backup *generators*, and electrically driven gas compressors should be avoided when determining what load to shed.

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

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

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

b. Opening bus tie breakers to increase *non-dispatchable load* lost by configuration shall be considered as L/R.

c. L/R selections will be minimized where affected *IESO-controlled grid delivery points* are not within *reliability* performance standards.

d. L/R selected to relieve post-contingency thermal overloading shall be:

   (i) Sufficient to comply with the thermal rating policy.

   (ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate "limited" time.

Generation Rejection Selections

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

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

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

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

b. G/R selections for single element *contingency events* shall be minimized.

c. G/R selected to relieve post-contingency thermal overloading shall be:

(i) Sufficient to comply with the thermal rating policy.

(ii) Sufficient to prevent loading beyond the long-time ratings if the lack of fast-acting control actions combined with the complexities of post-rejection operation will jeopardize respecting long-time ratings within the appropriate “limited” time.

d. G/R selections should avoid manual corrective measures following a G/R operation,

e. G/R selections should be made on a reasonable effort basis to address *market participant facility* concerns such as the:

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

(ii) Minimum number of unselected generating units, and

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

Generation Runback Selections

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

– End of Section –

Appendix C: RAS Restrictions during High Risk Operating State

<table>
<tr><th colspan="2">Contingency Type</th><th>High Risk Operating State Due to Adverse Weather within the Weather Advisory Area
(refer to notes A, B, C and D)</th><th>High Risk Operating State Due to Conditions not within the Weather Advisory Area
(refer to notes A, B and C)</th></tr>
<tr><td rowspan="2">500 kV
230 kV
115 kV</td><td>Recognized Double Element</td><td>No restrictions to G/R or L/R</td><td rowspan="2">The primary concern is adverse effects of a false RAS operation. The following restrictions therefore apply:
• G/R or runback is permissible provided its use is minimized.
• L/R is permissible, provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
<tr><td>Recognized Single Element</td><td>G/R or runback is permissible, provided:
• Arming is limited to outage periods or short-duration periods, or
• Its magnitude is reduced during adverse weather periods
G/R is permissible, provided the only other alternative is to remove the unit from service, or the unit would be automatically removed from service as a result of the initiating contingency.
L/R is permissible provided IESO-controlled grid system security criteria could not otherwise be satisfied.</td></tr>
</table>

(A) A *RAS* must NOT be utilized if a fail-to-trip condition is suspected.

(B) A *RAS* may be selectively used to provide additional *system security* beyond normal criteria, provided the restrictions in this table are observed.

(C) The restrictions in this table do not apply to *RAS* selections for extreme contingencies.

(D) The Weather Advisory Area is within 50 km of the circuits for which the *RAS* is selected.

– End of Section –

References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
PRO-408	Market Manual 1.5: Market Registration Procedures
MDP_PRO_0024	Market Manual 2.8: Reliability Assessments Information Requirements
IMP_PRO_0033	Market Manual 7.2: Near-Term Assessments and Reports
IMP_PRO_0035	Market Manual 7.3: Outage Management
IMP_GOT_0002	Market Manual 7.6: Glossary of Standard Operating Terms
IMO_PLAN_0001	Market Manual 7.8: Ontario Power System Restoration Plan
IMO_PLAN_0002	Market Manual 7.10: Ontario Electricity Emergency Plan
IESO_PRO_0874	Market Manual 11.2: Ontario Reliability Compliance Program

– End of Document –