PUBLIC

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PROCEDURE

Market Manual 7: System Operations

Part 7.3: Outage Management

Issue 40.0

This document outlines the process *market participants* must follow in submitting *outage* requests for facilities

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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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N/A	

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Reference (Section and Paragraph)	Description of Change
Section 4.2.4	Revised content to specify testing requirements for *hourly demand response* resources, and to allow compensation for out of market activations for *hourly demand response* resources. These changes are applicable to the *demand response auction* held in December 2019, for the *commitment period* beginning May 1, 2020.

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 Procedures

The “System Operations Manual” is Series 7 of the *market manuals*, where this document forms “Part 7.3: Outage Management”.

– End of Section –

1. Introduction

1.1 Purpose

This document is provided for *market participants* as a guide to *outage* management for facilities and equipment connected to the *IESO-controlled grid*, or which may affect the operation of the *IESO-controlled grid*. This includes *outage*s to transmission facilities defined as constituting elements of the *IESO-controlled grid* under the *market rules* and various *operating agreements* between the *IESO* and *market participants*.

1.2 Scope

This procedure is intended to provide *market participants* with a summary of the steps and interfaces involved in the *outage* management process. The procedural workflows and steps described in this document serve as a roadmap for *generation facilities*, *transmitters*, *distributors* and *wholesale customers* that participate in the *IESO*-administered markets, and reflect the requirements set out in the *market rules* and applicable *IESO* policies and standards.

The *IESO* considers a piece of equipment to be in an *outage* state when it is removed from service, in a state other than its normal state, unavailable for connection to the system, temporarily derated, restricted in use, or reduced in performance. This includes de-staffing of a *generation unit* during a period when *market participants* do not expect the unit to be scheduled to provide *energy* or *operating reserve*. Auxiliary equipment is also considered to be in an *outage* state when it is not available for use.

Outage management, based upon the set of permissions and requirements specified in the *market rules*, comprises the following aspects:

- Coordination and submission of *outage* requests by *market participants*,
- Assessment of *outage* requests by the *IESO*,
- Identification of *reliability* issues associated with *outage*s, leading to actions including rejection, revocation, and at risk declarations of the *outage* request, and recall of the equipment on *outage* by the *IESO*,
- Compliance obligations, and
- *Outage* compensation in the event of revocation or recall.

In support of these aspects, this procedure details the conditions, actions and timelines required for *outage* management by *market participant*s. The procedure is based on obligations expressed in the *market rules*, as well as standards established by the North American Electric Reliability Council (*NERC*) and criteria established by the Northeast Power Coordinating Council (*NPCC*).

1.3 Roles and Responsibilities

The following table outlines the responsibilities of the groups involved in the *outage* management process:

Table 1-1: Roles and Responsibilities

Group	Responsibility
Market participants that meet the *IESO*'s *outage* reporting requirements	• Coordinate and submit *outage*s using *IESO* reports and recommendations, • Submit requests to implement *outage*s to their facilities or equipment within the required timeframe to the *IESO*, • Request final approval prior to start of the *outage*, • Confirm the start of the *outage*, • Confirm the completion of *outage*, • Request permission to return equipment to service, • Confirm the restoration of equipment to normal state with the *IESO*, and • Register new equipment information and update information for existing equipment via Online IESO[1].
IESO	• Assess *outage* requests for potential impact to *reliability* and/or operability[2] of the *IESO*-controlled grid, • Provide advance and final approval for *outage* requests, • Reject an *outage* request, and revoke or recall previously approved *outage*s for *reliability* reasons, • Coordinate *outage*s and tests if required, and • Grant permission for equipment to return to service.

1.4 IESO Planned IT Outages

Market participants are normally notified about planned Information Technology (IT) *outage*s to market-facing tools and applications through weekly bulletin emails. Details for all planned IT *outage*s are also posted on the *IESO*'s Planned IT Outages website.

For unforeseen IT *outage*s, *market participants* are notified via an Advisory Notice and/or via a message through the Market Participant Interface.

[1] Online IESO is an online tool for *market participants* to submit data to the *IESO*, accessible at https://online.ieso.ca.

[2] For the purposes of this document, "operability" ensures the flexibility to safely operate the *IESO-controlled grid* considering, for instance, the risk of unplanned system or generation changes, and variable generation behaviour.

1.5 Confidentiality

Under the *market rules*, the *IESO* is required to *publish planned outage* information while respecting the confidentiality of *market participants*. As a result, *outage* requests submitted by *market participants* may be classified as confidential, and protected appropriately.

In addition, the *Adequacy* Reports will aggregate *outage* information to protect the confidentiality of *market participants*. All planned *transmission system outage*s will be published for information. This may include transmission elements that are not owned by a *transmitter*.

Outage information will only be exchanged with Reliability Coordinators (RCs) and Balancing Authorities (BAs) who are signatories to the *NERC confidentiality agreement* or who are otherwise legally bound to withhold and keep confidential *outage* information from any person competing with a *market participant* who provided the information.

Market participants may choose to share *outage* information with other *market participants* by granting third party viewership of their equipment via Online IESO. A single *outage* request may contain both, equipment with and without third party viewership access. In such cases, third party viewers will only see the equipment to which they have access.

1.6 Contact Information

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

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

– End of Section –

2. Outage Management Overview

Market participants are required to request permission and receive approval for *planned outages* from the *IESO* in order to ensure that equipment *outage*s do not impact the *reliability* and/or operability of the *IESO-controlled grid*. *Market participants* with equipment that affects the operation of the *IESO-controlled grid* may not remove equipment or facilities from service except in accordance with the rules for *Outage* Coordination contained in *Market Rule* Chapter 5, Section 6.4.3 (*MR* Ch. 5, Sec. 6.4.3) and this *market manual*.

The *IESO*'s *outage* management system uses the the Control Room Operations Window (CROW) *outage* coordination and scheduling system. *Market participants* are required to submit information that provides the *IESO* with a better understanding of the priority, scope and impact of the *outage* request as described in Sections 2.1 to 2.5.

Market participants must submit their *planned outages* into one of four *advance approval* processes in order to receive *advance approval*. Each process has a unique set of eligibility criteria and submission/approval deadlines further described in Section 2.7.

Forced, urgent, information and opportunity *outage*s are *outage*s that *market participants* are unable to submit in accordance with the submission requirements for *planned outages*, however these types of *outages* must still be submitted to the *IESO* as either a notification or a late request for *advance approval* as described in Section 2.2.

2.1 Criticality Levels of Equipment

The level of equipment criticality dictates the *advance approval* timeframe within which a planned *outage* request must be submitted (see Table 2-1). For example, *planned outages* to critical equipment must be submitted at least 17 days prior to the start of the coverage period (under the Weekly *Advance Approval* process), whereas *planned outages* to low-impact equipment must be submitted two days prior to the scheduled date of the *outage* (under the 1-Day *Advance Approval* process). Section 2.7 describes *advance approval* processes and eligible equipment in further detail.

The *IESO* notifies *market participants* of equipment criticality levels via Online IESO, upon completion of facility assessment. When submitting *outage* requests, *market participants* are required to identify the impacted equipment and the *outage* management system will auto-populate the criticality level.

Table 2-1: Criticality Levels of Equipment

Criticality Level	Description	Examples	*Advance Approval* Submission Timeline
Critical Equipment[3]	Equipment that has a material impact on the *reliability* and/or operability of the *IESO-controlled grid* or the *interconnection* when removed from service or restricted.	Equipment that impact power system stability limits	• Must be submitted for Weekly *Advance Approval* • May be submitted for Quarterly *Advance Approval*
Non-critical Equipment[3]	Equipment that does not typically have a material impact on the *reliability* and/or operability of the *IESO-controlled grid* or the *interconnection* when removed from service or restricted.	• Equipment in *local areas* • *Generation facilities*	• Must be submitted for 3-Day *Advance Approval* • May be submitted for Quarterly or Weekly *Advance Approval*
Low-impact Equipment	Equipment that has little to no impact on the *reliability* and/or operability of the *IESO-controlled grid* or the *interconnection* when removed from service or restricted.	• Loads • Duplicated protection relays	• Must be submitted for 1-Day *Advance Approval* • May be submitted for Quarterly, Weekly *Advance Approval*

[3] Refer to Section 2.7.5 for submission timelines for *outage* requests to critical and non-critical equipment with low-impact attributes.

2.2 Priority Codes

Priority codes identify the priority of the *outage* request. Refer to Table 2-2: Priority Codes below. The *IESO* uses this information to determine the level of urgency to implement the *outage* and to prioritize competing *outage* requests. For example, an urgent *outage* request gets a higher priority compared to an opportunity *outage* request.

Refer to Section 2.2.1 for more information on how the *IESO* determines *outage* priority.

Market participants are required to use one of the following Priority Codes when submitting their *outage* request.

Note: Priority Codes cannot be changed by *market participants* once they have been submitted.

Table 2-2: Priority Codes

Priority Codes	Description	Examples	Obligation to Notify *IESO*
Forced	Non-discretionary *outage*s on equipment that has been automatically or manually removed from service for equipment protection, public safety, environmental concerns or regulatory requirements are classified as *forced outages*. Such *outage*s have little to no timing flexibility and have precedence over all Priority Codes.	• Transformer forced out of service due to equipment failure	*Market participants* are required, as far in advance as possible, to promptly notify the *IESO* of any *forced outage* (*MR* Ch. 5, Sec. 6.3.4).
Urgent	Non-discretionary *outage*s on equipment that must be manually removed from service for equipment protection, public safety, environmental concerns or regulatory requirements are classified as urgent *outage*s.	• SF6 breaker low gas alarm that requires a breaker *outage* for gas top-up within a limited timeframe	*Market participants* are required to coordinate *outage* timing with the *IESO*, where possible, to occur at a date and time that satisfies the *market participant*'s need and minimizes the impact to the *IESO-controlled grid*.
Planned	Discretionary *outage* requests that are scheduled to perform preventive maintenance, repairs, inspections, de-staffing and testing for facilities/equipment are classified as *planned outages*.	• *Generation facility* scheduled maintenance • Breaker trip coil test	*Market participants* must adhere to submission deadlines explained in Section 2.7 of this manual. (*MR* Ch. 5, Sec. 6.2.2K and 6.2.2L).

Priority Codes	**Description**	**Examples**	**Obligation to Notify *IESO***
Opportunity	In cases where *market participants* are presented with an unexpected opportunity to accomplish work that was not previously planned, they may submit an *outage* request with the opportunity Priority Code.	• Additional testing is required to expedite the completion of an in-progress *forced outage* to a *generation facility*. • An opportunity to perform maintenance to a facility that is made grid-incapable by another *outage*.	The *IESO* is not obligated to consider such submissions, but may do so where the opportunity presents low to negligible risk to the *reliability* and/or operability of the *IESO-controlled grid* and or to the *IESO.* (*MR* Ch. 5, Sec. 6.4.6).
Information	*Outages* that are exempt from submission requirements outlined in Appendix B, but are submitted for informational purposes only, are classified as information *outage*s.	• *Generation facility* unavailable for condense • Switch on manual operation only	No obligation. *Market participants* may, as far in advance as possible, notify the *IESO* of any information *outage*, using their *outage* submission tools.
Force Extended	This code is not available to *market participants* when submitting *outage* requests. However, if the end time of a planned, opportunity, or information *outage* requests get extended their Priority Code will be updated to forced extended.	• Adverse weather conditions delay the completion of a scheduled *outage*	*Market participants* are required to notify the *IESO* of any forced extension as far in advance as possible, using their *outage* submission tools and by telephoning the *IESO*.

2.2.1 Determining Outage Priority

The *IESO* determines priority of *outage*s in order to approve, reject, revoke and recall *outage*s in a consistent and uniform manner.

Outage priority for approval (as per *MR* Ch. 5, Sec. 6.4.2) is based on the criteria listed below:

- **Criteria 1: Priority Code**

The Priority Code of an *outage* request is the primary determinant of *outage* priority. The order of precedence is as follows:

I. Forced

II. Urgent

III. Planned

IV. Opportunity

For example, when approving *outage*s, an urgent *outage* request gets priority over a planned or opportunity *outage* request.

- **Criteria 2: Advance approval timeframe**

Within *planned outages*, the order of precedence is as follows:

I. *Outages* submitted for Quarterly *Advance Approval*

II. *Outages* submitted for Weekly *Advance Approval*

III. *Outages* submitted for 3-Day *Advance Approval*

IV. *Outages* submitted for 1-Day *Advance Approval*

For example, a *planned outage* request submitted for Weekly *Advance Approval* gets priority over a *planned outage* request submitted for 3-Day *Advance Approval*. However, an urgent *outage* request submitted five days ahead of the planned start time gets priority over a *planned outage* request submitted under the Weekly *Advance Approval* process.

- **Criteria 3: Priority date**

For urgent and opportunity *outage*s, the submission date and time determine *outage* priority. The earlier the submission, the higher is the priority of the *outage* request.

For *planned outages* submitted within the same *advance approval* timeframe, the submission date and time determine *outage* priority.

For example:

If…	Then…
The following *outage*s are submitted for approval: *Outage* A: Opportunity *outage* submitted three days ahead of the planned start time *Outage* B: Urgent *outage* submitted five days ahead of the planned start time *Outage* C: *Planned outage* submitted for the Weekly *Advance Approval* process *Outage* D: Opportunity *outage* submitted five days ahead of the planned start time *Outage* E: *Planned outage* submitted for the 3-Day *Advance Approval* process	*Outage* priority will be as follows: 1. *Outage* B 2. *Outage* C 3. *Outage* E 4. *Outage* D 5. *Outage* A

To determine priority when rejecting, revoking *advance approval* or recalling *outage*s, the *IESO* shall follow the reverse order of the criteria listed above (*MR* Ch. 5, Sec. 6.4.13). Where an *outage* conflict exists and one or more conflicting *outage*s are rejected or revoked, the *IESO* may facilitate communication between the parties.

For example:

If…	Then…
The *IESO* determines a need to reject the following submitted *outage* requests: *Outage* A: Opportunity *outage* submitted three days ahead of the planned start time *Outage* B: Urgent *outage* submitted five days ahead of the planned start time *Outage* C: *Planned outage* submitted for the Weekly *Advance Approval* process *Outage* D: Opportunity *outage* submitted five days ahead of the planned start time *Outage* E: *Planned outage* submitted for the 3-Day *Advance Approval* process	*Outage*s will be rejected in the following order: 1. *Outage* A 2. *Outage* D 3. *Outage* E 4. *Outage* C 5. *Outage* B

If *market participants* make a significant change to the scope or time window of a previously submitted *outage* request, the *IESO* shall revise the priority date with the time at which such change notice was received by the *IESO*. Changes to the following *outage* request fields are considered to be significant changes:

- Planned Start (if changed to an earlier *outage* period level[4] start date/time)
- Planned End (if changed to a later *outage* period level[4] end date/time)
- Equipment Requested (if equipment is added or removed)
- Equipment Description
- Priority Code
- Constraint Information (if change in Constraint Code, value, and/or measure unit)
- Changes to any responses to low-impact questions (Refer to Section 2.5 for details)
- Change to the response to the Telemetry Scaling Impact question

The revised priority date will then be used to determine the priority for approval. In cases where *market participants* shorten the duration of a *planned outage* to remain within the original time window, the priority date associated with the initial submission will still be used to determine priority (*MR* Ch. 5, Sec. 6.4.15).

In cases where *market participants* wish to shorten the max recall time, they must verbally request the *IESO* to retain the original *outage* priority.

[4] Outage period level date/time refers to the date/times of the individual outage periods on the Details tab, not limited to the overall outage date/times.

2.3 Purpose Codes

Purpose Codes allow *market participants* to indicate the reason for the *outage* request. Refer to Table 2-3 below. This information is used by the *IESO* to determine the impact and purpose of the *outage* request. For example, an *outage* request submitted for a safety concern informs the *IESO* of the *market participant*'s urgent need compared to an *outage* request to conduct maintenance/repair testing which can be planned in advance.

Market participants are required to select one of the following Purpose Codes when submitting their *outage* request and input a description of the *outage's* purpose in the *outage* management system.

Note: Selection of Purpose Codes is based on the Priority Code. For example, 'Equipment Concern' code is available only if the *market participant* is submitting a forced or urgent *outage*. Similarly, the 'Repair' code is available only for *planned outages.* Refer to Section 2.6 for a mapping of Purpose and Priority Codes.

Table 2-3: Purpose Codes

Purpose Code	Description	Example
Maintenance Repair	*Outages* implemented to facilitate routine equipment maintenance and repair.	Annual transformer maintenance
Replacement	*Outages* implemented to replace aging or faulty equipment/facilities. In such cases, *market participants* must ensure the replacement is registered with the *IESO* as per Market Manual 1.2: Facility Registration, Maintenance and De-registration. The *outage* to replace the equipment/facility is typically followed by a need to carry out a commissioning *outage* as explained below.	Breaker replacement
Commissioning	*Outages* implemented to test new or modified equipment/facilities being connected to the *IESO*-controlled grid for the first time.	Commissioning of new *generation facility*
Testing	*Outages* implemented to facilitate testing of equipment/facilities not considered to be commissioning tests or activities.	*Generation facility* minimum load point testing
Equipment/Safety/ Regulatory/ Environmental Concerns	*Outages* implemented for non-discretionary purposes such as public safety, equipment protection, environmental concerns or regulatory requirements.	*Generation facility* derate due to restrictive forebay operating ranges
Favourable (Generation/ Transmission) Outage Condition/Favourable *Adequacy* Margin/ Expedite Return to Service	*Outages* having low to negligible risk to the *reliability* of the *IESO*-controlled grid and are implemented to accomplish work that would have otherwise been unable to proceed. **Note**: *Market participants* may select this code, however the *IESO* will assess and determine the *outage*'s impact on the *IESO-controlled grid*.	Transformer feeder *outage* during existing *outage* to connecting circuit

Purpose Code	Description	Example
Manually/Automatically Removed From Service	Unforeseen *outage*s that result in manual or automatic removal of equipment/facilities from service.	Unit trip from neutral overcurrent
Failed to Synch	Unforeseen *outage*s resulting from a failure to synchronize generation equipment/facilities to the *IESO-controlled grid*.	Unit breaker failed to synch
Segregated Mode of Operation	Outage to indicate generation or transmission equipment/facilities being disconnected from the *IESO*-controlled grid and connected to an external system, i.e. Quebec.	*Generation facility* connected to Quebec
Cyber Asset Change/ Relay Setting Change	*Outages* to indicate hardware/software changes for RTUs, gateways, routers, protection relays etc. intended to separate such requests from other general *planned outages.*	Software changes for RTU
Transmission Equipment Derating	*Outages* to indicate that a piece of transmission equipment is operating at a reduced equipment rating.	Transformer derating for degraded cooling
Switching	Short duration *outage* required to support the removal of equipment for a separate *outage* request.	Circuit terminals required for 15 min to switch circuit out of service
Telco Third Party Threat	Telecommunication *outage*s requested of Hydro One by a third party telecom provider	Third party company to perform protection and control maintenance of Access Multiplexer
Self-Bottling	Outages implemented to indicate that a variable generation resource is operating to a reduced maximum generation output due to constraints resulting from transmission element outages within the resource's facility. **Note:** This is to ensure that the centralized forecast predicts output of the station proportionate to their available capacity but capped at a derated maximum, rather than proportionate to their derated maximum as would be the case with a normal derate outage request.	100 MVA variable generation resource normally connected to two 50 MVA transformers, but one transformer is out-of-service
Icing	*Outages* implemented to indicate reduced generation capacity due to icing conditions.	Ice on wind turbines
Other	*Market participants* may use this Purpose Code for *outage*s being requested for any reason other than those listed above.	*Generation facility* unavailable for Generation Rejection

2.4 Constraint Codes

Constraint Codes identify the status of the equipment when the *outage* is under implementation. This information is used to determine the limitations on the equipment to determine the impact of the *outage* request on the *IESO*-controlled grid. For example, an 'In Service' code indicates the equipment is available and functional, whereas an 'Out of Service' code indicates the equipment will be unavailable for the duration of the *outage*.

Appendix C lists applicable Constraint Codes based on equipment type.

Market participants are required to use one of the following Constraint Codes when submitting their *outage* request.

Note: Selection of Constraint Codes is based on the Priority Code. For example, INFO and ABNO codes are only available for information *outage*s. Refer to Section 2.6 for a mapping of Purpose and Priority Codes.

Table 2-4: Constraint Codes

Constraint Code	Description	Examples
Out of Service (OOS)	Equipment is unavailable and removed from service.	• Breaker out of service
In Service (IS)	Equipment is available and in-service.	• Normally open switch required in-service
Derated To (DRATE)	Equipment cannot operate above a specified capability that is less than its rated capability.	• *Generation facility* derated to 50 MW
Must Run At[5] (MUSTRUN)	Equipment can only operate at a specified capability that is less than or equal to its rated capability.	• *Generation facility* must run at 50 MW
Hold Off (HOLDOFF)	Equipment has its reclosing capability blocked.	• Circuit hold off
Protection Out of Service (PROT OOS)[6]	Equipment's primary or back-up protection is unavailable in some capacity.	• Circuit's B Protection out of service
Breaker Fail Protection Out of Service (BF PROT OOS)[6]	A breaker's backup protection is unavailable in some capacity.	• Breaker Fail Protection for Breaker A out of service
Automatic Voltage Regulation or Power System Stabilizer Out of Service (*AVR*/PSS OOS)[6]	*Generation facility*'s *AVR* or PSS is unavailable in some capacity.	• *Generation facility AVR* out of service
Breaker Trip Coil Test (BTCT)	Breaker is undergoing a protection relay-initiated test operation.	• Breaker trip coil test for Breaker A

[5] While the 'Must Run At' and the 'Derated To' codes represent different limitations, the downstream software process at the *IESO*'s end will consider both values to mean the maximum capability for the duration of the *outage* request.

[6] *Market participants* are required to input a description of the equipment when using this Constraint Code.

Constraint Code	Description	Examples
Ancillary Service Out of Service (ASP OOS)[6]	Equipment's ability to provide a contracted *ancillary service* is restricted in some capacity.	• *Generation facility* unavailable for Black-start, Regulation or Voltage Control
Information (INFO)	Equipment has a condition or limitation that does not require approval from *IESO*.	• *Generation facility* unavailable for condense • Derated *dispatchable loads* with a *demand response capacity obligation*
Available But Not Operating (ABNO)	Mechanism for *generation facilities* to report they do not expect to participate in the market.	• *Generation facility* off-peak *demand* • *Generation facility* de-staffing

2.5 Low-impact Attributes

During *outage* request submission, *market participants* are required to answer certain questions to determine if their *outage* contains low-impact attributes, thereby making the equipment eligible for 1-Day Advance Approval, Auto *Advance Approval* and/or Final Approval in Advance (further explained in Section 2.7.5, Section 2.7.6 and Section 2.7.7, respectively). Low-impact attributes are used by the *IESO* to further define the scope and impact of the requested equipment.

Refer to Appendix D for a list of attributes and applicability.

For example: *Market participants* submitting an *outage* request for line protection out of service, they need to specify whether it is only a loss of redundancy. If they answer "Yes", the equipment is considered to have low-impact attributes.

Submission Timelines

The following are the submission timelines for *outage*s on equipment with low-impact attributes:

- Must be submitted for 1-Day *Advance Approval*
- May be submitted for Quarterly, Weekly or 3-Day *Advance Approval*
- May be eligible for Auto *Advance Approval* and/or Final Approval in Advance

2.6 Mapping Purpose, Constraint and Priority Codes

Each Priority Code applies to a set of Purpose and Constraint Codes. Table 2-5 below presents a mapping of all codes.

Table 2-5: Mapping of Purpose, Constraint and Priority Codes

Priority Code	Purpose Codes	Constraint Codes
Planned	• Commissioning • Cyber Asset Change • Maintenance • Other • Relay Setting Change • Repair • Replacement • Segregated Mode of Operation • Switching • Telco Third Party Threat • Testing	All except INFO and ABNO
	• Self Bottling	DRATE
Urgent	• Environmental Concerns • Equipment Concerns • Other • Regulatory Concerns • Safety Concerns • Switching • Telco Third Party Threat	All except INFO and ABNO
	• Icing • Self Bottling	DRATE
Opportunity	• Commissioning • Expedite Return to Service • Favourable *Adequacy* Margin • Favourable Generation Outage Condition • Favourable Transmission Outage Condition • Other • Segregated Mode of Operation • Switching • Testing	All except INFO and ABNO
	• Self Bottling	DRATE
Information	• Other • Transmission Equipment Derating	• INFO • ABNO

Priority Code	Purpose Codes	Constraint Codes
Forced	• Automatically Removed From Service • Environmental Concerns • Equipment Concerns • Failed to Synch • Manually Removed From Service • Other • Regulatory Concerns • Safety Concerns	All except INFO and ABNO
	• Icing • Self Bottling	DRATE

2.7 Timelines

2.7.1 General Requirements

Market participants may request Quarterly, Weekly, 3-Day or 1-Day *Advance Approval* for their *planned outages* (*MR* Ch. 5, Sec. 6.2.2K). This section explains the submission and assessment periods for each *advance approval* timeframe. Eligibility for *advance approval* is determined by equipment criticality, as explained in Section 2.1.

Each *advance approval* process is associated with distinct submission, study and coverage periods. For the purposes of *outage* submission guidelines described in this document:

- "Study period" refers to the period when the *IESO* assesses *planned outage* requests submitted for the associated *advance approval* process. The *IESO* will notify *market participants* of its assessment by the end of the study period.
- "Coverage period" refers to the implementation period for *outage*s that receive *advance approval* within the associated study period.
- *Market participants* must submit *outage* requests before the start of the associated study period, in order to receive *advance approval* for implementation during the associated coverage period.

Market participants must submit *forced outage* notifications when they occur and these will be addressed by the *IESO* immediately.

Market participants may submit urgent *outage* requests at any time. The *IESO* will study such requests as soon as possible.

Market participants may submit opportunity *outage* requests at any time. Such requests are considered late *planned outage* requests. The *IESO* is not obligated to consider such submissions, but may do so where the opportunity presents low to negligible risk to the *reliability* and/or operability of the *IESO-controlled grid* and or to the *IESO* (*MR* Ch.5, Sec. 6.4.6).

Market participants may submit information *outage* requests at any time. The *IESO* will use reasonable efforts to study such requests.

Table 2-6: Advance Approval Timelines and Eligibility

Advance Approval **Process**[7]	**Submission Requirement (Prior to Start of Coverage Period)**	**Approval Deadline (Prior to Start of Coverage Period)**	**Eligible Equipment**
Quarterly	3 months prior	1 month prior	• All equipment types may be submitted
Weekly	17 days prior	10 days prior	• Critical equipment must be submitted • Non-critical and low-impact equipment may be submitted
3-Day	5 *business days* prior	3 *business days* prior	• Non-critical equipment must be submitted • Low-impact equipment may be submitted
1-Day	2 *business days* prior	1 *business day* prior	• Low-impact equipment must be submitted • Critical and non-critical equipment with low-impact attributes must be submitted

Submission Timelines for Outages Supporting External RCs

Market participants may be required to conduct *outage*s to support work planned by external RCs. In cases where *market participants* are unable to submit such *outage* requests for *advance approval* within the deadlines for *planned outages*, they are required to submit such outages with an Urgent Priority Code and refer to the RC work request in the 'Purpose Description' field in the *outage* management system. The *IESO* will consider it as a *planned outage* when determining priority. Refer to Section 2.2.1 for details on determining *outage* priority.

Note: The *IESO*'s obligation to assess such *outage* requests is based on the *interconnection agreement* with the external RC.

2.7.2 Quarterly Advance Approval Process

The *IESO* facilitates long-term planning by offering *market participants* the option to receive approval for all *planned outages* up to eight months prior to the scheduled start time via the Quarterly *Advance Approval* process.

Outages submitted within this process get the highest priority compared to *planned outages* submitted under other timeframes, thus granting greater certainty to *market participants*. Refer to Section 2.2.1 for details on determining *outage* priority.

[7] Refer to Section 2.7.5 for submission timelines for *outage* requests to critical and non-critical equipment with low-impact attributes

Important

If an *outage* request is submitted for the Quarterly *Advance Approval* process after the submission deadline, the *outage* management system will automatically place the *outage* for assessment under the next Quarterly, Weekly, 3-Day or 1-Day *Advance Approval* process, as eligible, based on equipment criticality, 'Request Weekly AA' flag and planned start time.

The study and coverage periods for the Quarterly *Advance Approval* process are as shown in Figure 2-1.

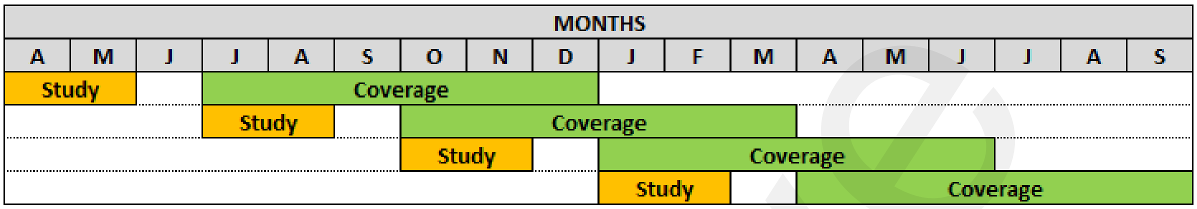


Figure 2-1: Quarterly Advance Approval Timeline

Study period for the Quarterly *Advance Approval* process begins at 00:00:00 EST on the first day of the period month and ends at 23:59:59 EST on the last day of the period month as shown in Figure 2-1. Coverage period for the Quarterly *Advance Approval* process begins 00:00:00 EST on the first day of the period month and ends at 23:59:59 EST on the last day of the period month as shown in Figure 2-1.

Note: The timelines for submission and assessment are inclusive of statutory holidays in Ontario and Saturdays and Sundays (Saturdays and Sundays hereafter referred to as weekend days).

By the end of the study period, the *IESO* will either:

- Provide *advance approval*, or
- Place the *outage* request in the 'At Risk' status

Market participants may choose to resubmit an *outage* placed in the 'At Risk' status at the end of a Quarterly study period. Resubmitted *outage* requests will retain the priority date of the original *outage* request if:

- the original *outage* was scheduled to begin in the first three months of the current coverage period, and
- it is resubmitted before the next study period, and
- the resubmitted outage is scheduled to begin during the corresponding six month coverage period (*MR* Ch. 5, Sec. 6.4.20).

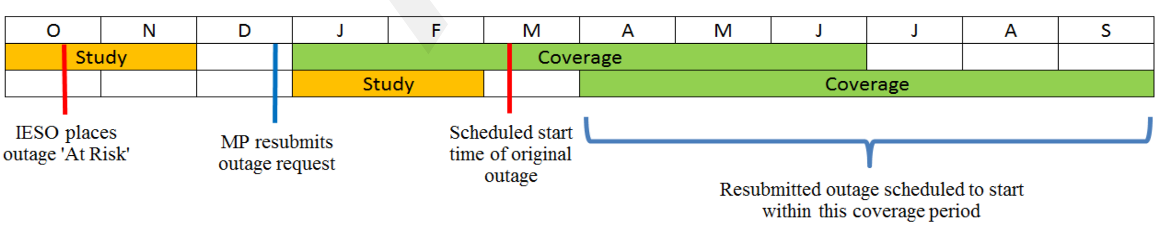


Figure 2-2: Criteria for 'At Risk' Outage Retaining Original Priority

The *IESO* will re-assess *outage*s placed in the 'At Risk' status at the end of the Quarterly study period during the next Quarterly, Weekly, or 3-Day *Advance Approval* process, as applicable based on equipment criticality and the status of the 'Request Weekly AA' flag.

Example A:

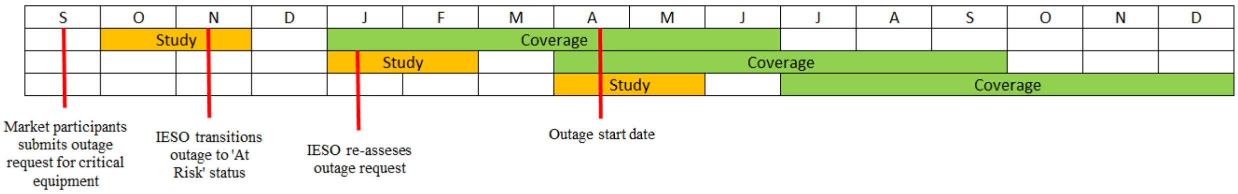


Figure 2-3: 'At Risk' Outage Reassessment – Example A

In the above figure, the *market participant* submits a request in September for an *outage* to critical equipment beginning in April of the following calendar year. The *IESO* studies the request during the October-November study period and transitions the *outage* to 'At Risk' status.

The *IESO* will re-assess the request during the January-February study period for Quarterly *Advance Approval*.

If…	Then…
The *IESO* transitions the request to 'At Risk' status during the January-February study period	The *outage* will be re-assessed in the next Weekly *Advance Approval* process

Example B:

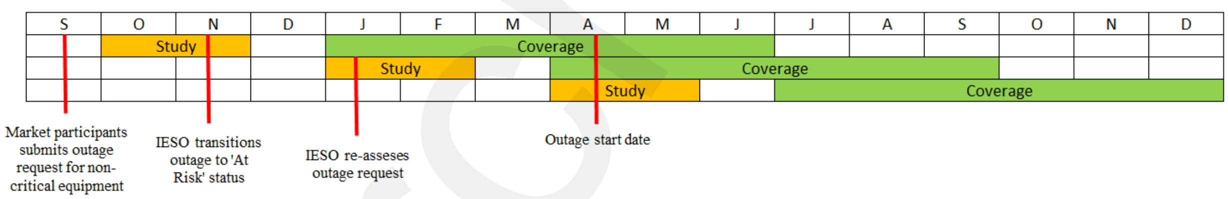


Figure 2-4: 'At Risk' Outage Reassessment – Example B

Using the same timelines as Example A, the *market participant* submits an *outage* request for non-critical equipment for Quarterly *Advance Approval*. If the *IESO* transitions it to 'At Risk' status during the October-November and the January-February study periods, the *outage* will be re-assessed during the next 3-Day *Advance Approval* process.

If…	Then…
The *outage* request has the 'Request Weekly AA' flag	The *IESO* will re-assess the request in the next Weekly *Advance Approval* process following the February study period

2.7.3 Weekly Advance Approval Process

Planned outage requests for critical equipment must be submitted for Weekly *Advance Approval*.

Market participants may also submit *planned outage* requests containing only non-critical or low-impact equipment under this process by selecting the "Request Weekly AA" flag in the *outage* management system.

Outages submitted within this process get a higher priority compared to *planned outages* submitted under 3-Day and 1-Day timeframes, thus granting greater certainty to *market participants* for *outage*s to non-critical or low-impact equipment (that are required to be submitted within the 3-Day and 1-Day processes respectively). Refer to Section 2.2.1 for details on determining *outage* priority.

Important

As explained in Section 2.1, the criticality of equipment will be auto-populated in the *outage* management system during *outage* submission. If *outage*s to critical equipment are not submitted within the Weekly *Advance Approval* process, the tool's auto-validation feature will not allow the *outage* submission to be completed.

The *IESO* will also study *outage*s with critical equipment and non-critical or low impact equipment with the "Request Weekly AA" flag placed in the 'At Risk' status from the Quarterly *Advance Approval* process during this time.

The study and coverage periods for the Weekly *Advance Approval* process are as shown in Figure 2-5.

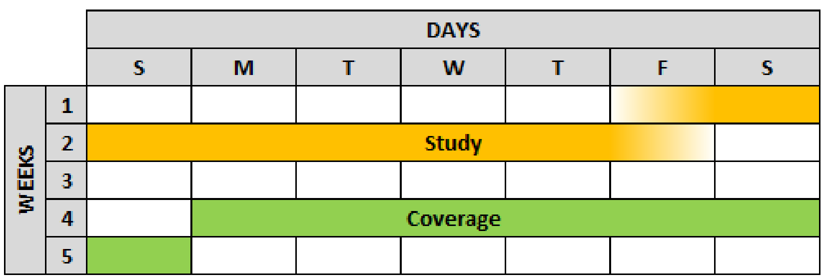


Figure 2-5: Weekly Advance Approval Timeline

Study period for the Weekly *Advance Approval* process begins at 16:00:00 EST on Friday and ends at 15:59:59 EST on the following Friday as shown in Figure 2-5.

Coverage period for the Weekly *Advance Approval* process begins 00:00:00 EST on Monday and ends at 23:59:59 EST on the following Sunday as shown in Figure 2-5.

Note: The timelines for submission and assessment are inclusive of statutory holidays in Ontario and weekend days.

For example, if the *outage* is scheduled to start on a Monday, the request must be submitted at least 17 days prior to the start of the *outage*. If the *outage* is scheduled to start on a Friday, the request must be submitted at least 21 days prior to the start of the *outage*.

By the end of the study period, the *IESO* will either:

- Provide a Weekly *Advance Approval*, or
- Reject the *outage* request

Note: *Outage* requests rejected during the Weekly *Advance Approval* process will not be re-assessed by the *IESO*. *Market participants* may resubmit rejected *outages* as new requests.

At this stage, the *IESO*, based on significant changes in system conditions such as *forced outages* and changes to Ontario *demand* forecast, may also revoke Quarterly *Advance Approval*s if implementation of the *outage* will impact the *reliability* of the *IESO-controlled grid* (*MR* Ch. 5, Sec. 6.4.9).

2.7.4 Three-Day Advance Approval Process

Planned outage requests for non-critical equipment must be submitted for 3-Day *Advance Approval*.

Market participants may also submit *planned outage* requests containing only low-impact equipment under this process. *Outages* submitted within this process get a higher priority compared to *planned outages* submitted under 1-Day timeframe, thus granting greater certainty to *market participants* for *outage*s to low-impact equipment (that are required to be submitted within the 1-Day process). Refer to Section 2.2.1 for details on determining *outage* priority.

The *IESO* will also study *outage*s with non-critical equipment placed in the 'At Risk' status from the Quarterly *Advance Approval* process during this time.

This process repeats daily on *business days* with study and coverage periods as shown in Figure 2-6.

		DAYS						
		S	M	T	W	T	F	S
WEEKS	1			Study				
	2	Coverage						

		DAYS						
		S	M	T	W	T	F	S
WEEKS	1				Study			
	2			Coverage				

Figure 2-6: Three-Day Advance Approval Timeline

Note: In Figure 2-6, the timeline on the left illustrates a coverage period that falls on a weekend, and the timeline on the right illustrates a coverage period that falls on a weekday.

Study period for the 3-Day *Advance Approval* process begins at 16:00:00 EST on *business days* and ends at 15:59:59 EST, two *business days* later as shown in Figure 2-6.

Coverage period for the 3-Day *Advance Approval* process begins 00:00:00 EST on the fifth *business day*[8] after the beginning of the study period, and ends at 23:59:59 EST on the same *business day*, as shown in Figure 2-6.

By the end of the study period, the *IESO* will either:

- Provide an *advance approval*, or
- Reject the *outage* request

Note: *Outage* requests rejected during the 3-Day *Advance Approval* process will not be re-assessed by the *IESO*. *Market participants* may resubmit rejected *outages* as new requests.

At this stage, the *IESO* may also revoke Quarterly and Weekly *Advance Approval*s if implementation of the *outage* will impact the *reliability* and/or operability of the *IESO-controlled grid* (*MR* Ch. 5, Sec. 6.4.9).

[8] Statutory holidays and weekend days that precede a *business day* are included in that *business day* (i.e. Saturday, Sunday and Monday equal one *business day*).

2.7.5 One-Day Advance Approval Process

Planned outage requests containing only low-impact equipment must be submitted for 1-Day *Advance Approval*.

Market participants may also submit *planned outage* requests containing critical and non-critical equipment with low-impact attributes under this process, if eligible. Appendix D lists eligibility criteria for 1-Day *Advance Approval*.

This provides additional flexibility to *market participants* who are otherwise required to submit *outage*s to critical and non-critical equipment in the Weekly and 3-Day *Advance Approval* processes, respectively.

Refer to Appendix D for a list of eligibility criteria for 1-Day *Advance Approval*.

For example,

If…	Then…
A *market participant* submits an *outage* request, less than five *business days* prior to the scheduled start time, to a *generation facility* with a '*Automatic Voltage Regulation* or Power System Stabilizer Out of Service (*AVR*/PSS OOS)' Constraint Code AND answers "Yes" to the "Only a Loss of Redundancy" question	The *outage* will be eligible for 1-Day *Advance Approval*.

The 1-Day *Advance Approval* process repeats daily with study and coverage periods as shown in Figure 2-7.

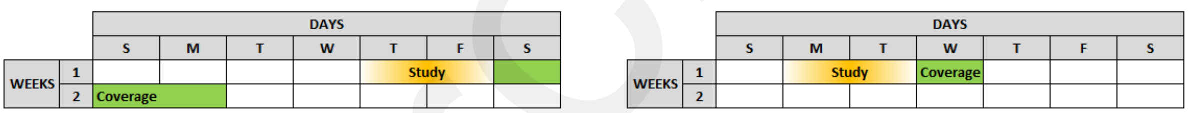


Figure 2-7: One-Day Advance Approval Timeline

Note: In Figure 2-7, the timeline on the left illustrates a coverage period that falls on a weekend, and the timeline on the right illustrates a coverage period that falls on a weekday.

Study period for the 1-Day *Advance Approval* process begins at 16:00:00 EST on *business days* and ends at 13:59:59 EST, one *business day* later, as shown in Figure 2-7.

Coverage period for the 1-Day *Advance Approval* process begins 00:00:00 EST on the second *business day*[9] after the beginning of the study period and ends at 23:59:59 EST on the same *business day*, as shown in Figure 2-7.

[9] Statutory holidays and weekend days that precede a *business day* are included in that *business day* (i.e. Saturday, Sunday and Monday equal one *business day*).

By the end of the study period, the *IESO* will either:

- Provide an *advance approval*, or
- Reject the *outage* request.

At this stage, the *IESO* may also revoke Quarterly, Weekly and 3-Day *Advance Approvals* if implementation of the *outage* will impact the *reliability* and/or operability of the *IESO-controlled grid* (*MR* Ch. 5, Sec. 6.4.9).

2.7.6 Auto Advance Approvals

Outage requests for low-impact equipment or equipment containing low-impact attributes may be eligible for Auto *Advance Approval* (Auto AA) when submitted via the *outage* management system. *Market participants* are required to answer certain questions to determine their eligibility for Auto AA. Refer to Appendix D – Column D in the table lists the questions that will be asked to *market participants* during *outage* request submission to determine eligibility for Auto AA.

Based on the answers provided by *market participants*, the tool will establish eligibility for and grant Auto AA. The tool will also check that there are no conflicting *outage*s, as explained in Section 3.2.3.

The *IESO* also has the ability to mark equipment for exclusion from the Auto AA process. For example, breaker failure protection *outage* to a critical breaker could be excluded from Auto AA despite correctly responding to the low-impact questions outlined in Appendix D.

Priority for *outage*s that are granted Auto AA will be based on the time of submission and *advance approval* process they would have been manually studied in by the *IESO*. This ensures the priority is aligned with the *IESO*'s manual assessment of the *outage*.

For example, if an *outage* request with non-critical equipment was submitted and auto-approved within the Quarterly process it would have a Quarterly *Advance Approval* priority. However, if the same *outage* request was submitted and auto-approved after the Quarterly submission deadline, it would have a 3-Day *Advance Approval* priority, based on equipment criticality and submission timeframe.

Going back to the example stated in Section 2.7.5, the *outage* request for the *generation facility* is deemed eligible for 1-Day *Advance Approval*. Now,

If…	Then…
A *market participant* submits an *outage* request, **less than** five days prior to the scheduled start time, to a *generation facility* with a '*Automatic Voltage Regulation* or Power System Stabilizer Out of Service (*AVR*/PSS OOS)' Constraint Code, AND The *market participant* answers the low-impact question as follows: Only a Loss of Redundancy? = **YES**	The *outage* will be granted Auto AA with a 1-Day *Advance Approval* priority
A *market participant* submits an *outage* request, 18 days prior to the scheduled start time, to a *generation facility* with a '*Automatic Voltage Regulation* or Power	The *outage* will be granted Auto AA with a Weekly *Advance Approval* priority

If…	Then…
System Stabilizer Out of Service (*AVR*/PSS OOS)' Constraint Code, AND The *market participant* answers the low-impact question as follows: Only a Loss of Redundancy? = **YES**	

The tool offers certainty to *market participants* by way of the automated approval, however *outage* priority will be based on manual assessment.

2.7.7 Final Approval in Advance

A subset of *outage*s for low-impact equipment or equipment containing low-impact attributes that are deemed eligible for Auto AA may receive Final Approval in Advance (FAA). The *IESO* determines eligibility for FAA based on the impact to the *IESO-controlled grid*, on a case by case basis.

Refer to Appendix D for criteria used to grant FAA.

The *outage* management system will transition the *outage* request to 'Auto AA' status and display a flag for *market participants* to confirm the *outage* request is eligible for FAA. On the day of the *outage*, the tool will automatically transition the *outage* to 'Final Approved' status.

For example,

If…	Then…
A *market participant* submits an *outage* request, five days prior to the scheduled start time, to a *generation facility* with a 'Protection Out of Service (PROT OOS)' Constraint Code and provides the following answer to the low-impact question: • "Only a Loss of Redundancy?" = **YES** and • Max Recall is ≤ 15 minutes	The *outage* will be transitioned to 'Auto AA' status and a flag will be displayed to confirm the *outage* is eligible for FAA. On the day of the *outage*, the *outage* request will be automatically transitioned to 'Final Approved' status. The *market participant* is not required to request final approval to implement the *outage.*

Market participants who have received FAA for their *outage*s are not required to request final approval in order to implement the *outage*.

The *IESO* may revoke the FAA of an *outage* request if it impacts the *reliability* and/or operability of the *IESO-controlled grid* and notify the *market participant*. In such cases the *market participant* must verbally request final approval to commence the *outage* by telephoning the *IESO*.

Outage requests submitted for equipment that is already scheduled out-of-service under a single, planned outage request with an 'Out of Service (OOS)' Constraint Code will be eligible for FAA provided the new outage request:

- Contains the same or a subset of the equipment scheduled out-of-service,
- Has an overall and period level planned start and end date that is the same, or within the same time period, as the existing outage request, and
- Has been manually selected by the IESO to be eligible for FAA.

2.7.8 Submission Deadlines

Figure 2-8 displays *outage* submission and *IESO* review timelines:

at least 3 months prior to coverage period start	• Submit outage requests for Quarterly *Advance Approval*
1 month prior to coverage period start	• IESO approves or transitions the outage into At-Risk status for the quarterly period
by 16:00 EST at least 17 days prior to coverage period start	• Submit outage requests for Weekly Advance Approval
by 16:00 EST 1 week prior to coverage period start	• IESO approves or rejects the request for Weekly Advance Approval.
by 16:00 EST 5 *business days* prior to coverage period start	• Submit outage request for 3-day *Advance Approval*
by 16:00 EST 3 *business days* prior to coverage period start	• IESO approves or rejects the request for 3-day *Advance Approval*
by 16:00 EST 2 *business days* prior to coverage period start	• Submit outage request for 1-day *Advance Approval*
by 14:00 EST 1 *business day* prior to coverage period start	• IESO approves or rejects the request for 1-day *Advance Approval*
Just prior to outage start	• Request final approval to begin outage (Not applicable for outages that receive final approval in advance) • IESO provides final approval or revokes *advance approval*
After IESO provides final approval	• Implement outage

Figure 2-8: Outage Submission and IESO Review Timeline

– End of Section –

3. Procedural Workflow

3.1 Facility Registration

Market participants are required to submit information regarding new or changes to existing facilities and equipment to the *IESO* via the online registration process outlined in Market Manual 1.2: Facility Registration, Maintenance and De-Registration.

The *IESO* will assess the submitted information to determine whether the equipment affects the operation of the *IESO-controlled grid* and communicate their assessment to *market participants* via Online IESO. *Market participants* are notified of their equipment's criticality level at this point. Changes to the *IESO-controlled grid* or system operating limits may require the *IESO* to review and update criticality levels of equipment.

Market participants whose facilities or equipment are determined to impact the *IESO*-controlled grid's *reliability* will be required to report *outage*s to the *IESO*. Refer to Appendix B for the detailed criteria that the *IESO* uses to assess *outage*-reporting requirements. *Outages* to system auxiliaries associated with this equipment must also be reported as identified in Appendix B.

Market participants may submit an *exemption application* according to the process outlined in the Market Manual 2.2: Exemption Application and Assessment procedure to apply for facility equipment to be entirely or partially exempted. Requests for *exemptions* from *outage* reporting are assessed by the *IESO* on a case-by-case basis as specified in *MR* Ch. 1, Sec 14. Assessments are communicated to *market participants* via Online IESO.

Market participants may also register one or more *control centres* via the online registration process to represent the location of their real-time operations. This facilitates the submission of *outage*s that are not associated to a particular station, e.g. SCADA systems.

3.2 Outage Coordination

The *IESO* facilitates the *outage* coordination process for *market participants* by providing the following:

- Undesirable situations – outlined in this manual
- Outage planning guidelines – confidential reports published by the *IESO* and embedded in the *outage* management system
- Conflicting Constraint Codes– embedded in the *outage* management system
- Conflict checking feature– embedded in the *outage* management system
- Outage Coordination for Capacity Exports
- *IESO* Reports – public reports published by the *IESO*

3.2.1 Undesirable Situations

When assessing *outage* requests, the *IESO* will use the following general criteria to identify any undesirable situations the *outage* request may result in:

- Negative impacts on the *reliability* (*security* and/or *adequacy*) and/or operability of the *IESO-controlled grid*, or
- Capacity and *energy* shortfalls, or
- Material impact on the operation of the *IESO-administered markets* (*MR* Ch. 5, Sec. 6.1.1).

Market participants may request to reposition their scheduled *outage*s based on their priority date, to avoid these undesirable situations.

3.2.2 Outage Planning Guidelines

The *IESO* will issue confidential *outage* planning guidelines to facilitate the assessment of grid *reliability*. The *outage* planning guidelines will assist *market participants* to avoid undesirable situations when scheduling *outage*s. The guidelines will provide the following information:

- **Transmission Group:** the category used to group associated transmission elements and/or *generation facilities*, specified along with timeframe. There are some groups with the same name succeeded by a number. These were created to account for all possible combinations of the elements within that group. For example, if the original Transmission Grouping was defined as Group A, for implementation it was broken down into Group A (1) and Group A (2) as follows:

Transmission Grouping	Transmission element	Threshold	
Group A	Line A/Line B Line C	1	Original Group
Group A (1)	Line A Line C	1	Implemented Groups
Group A (2)	Line B Line C	1	

- **Timeframe:** the applicable seasonal timeframe, specified with the transmission group name. Where not specified, the group will apply throughout the year. Table 3-1 defines seasonal timeframes:

Table 3-1: Seasonal Timeframe

Timeframe	From	To
All season	01-Jan	01-Jan
Summer	15-May	14-Sep
Winter	15-Nov	14-Mar
Spring	15-Mar	14-May
Fall	15-Sep	14-Nov

- **Element:** the specific piece of equipment within the group.

  Note: The bus must be included in the *outage* request if all bus breakers are out of service. The line disconnect must be included in the *outage* request if all terminal breakers are out of service.

- **Threshold:** the number of elements from the list that are permitted out of service at one time.

  For example, a threshold of 2 means only two elements from the list can be scheduled out of service at the same time without any conflict.

- **Reason:** the phenomena causing the conflict. This is based on the *IESO*'s assessment of situations that would:
  - compromise the *reliability* of the *transmission system*,
  - result in the inability to maintain the system within system operating limits using normal operating procedures, or
  - result in the inability to restore the *transmission system* to normal operating conditions following a respected contingency.

  For example, phenomena might comprise of pre and post contingency thermal concerns, pre and post contingency voltage concerns, pre and post contingency stability concerns, black-start restoration paths, or resource constraints.

- **Distribution:** the list of *market participants* who will be notified of the *outage* planning guideline. The distribution list will only include those *market participants* that own or operate equipment in the transmission group.

  For example, in Table 3-2 below, all *market participants* that own or operate any section of Line X will be on the distribution list. *Outages* for equipment tapped off Line X would not be restricted and therefore, would not be on the distribution list.

Table 3-2: Sample Outage Planning Guideline

Transmission Group	Transmission Elements	Threshold	Reason	Distribution
Group 1	Line X	1	Thermal concerns	
	Line Y			

M*arket participants* will be able to access the guideline at the IESO Reports webpage under Participant Reports. The *IESO* will periodically review the *outage* planning guideline and updates will be published as per the Baseline schedule.

3.2.3 Conflicting Constraint Codes

Upon submission of *outage* requests, the *outage* management system will check *outage*s for equipment with conflicting Constraint Codes for the same time period. For example, Generator A has an *outage* request with 'ABNO' Constraint Code that overlaps with another request for Generator A to be OOS.

Outage requests are considered to be in conflict when all of the following are true:

- The *outage* request priority codes are Forced, Forced Extended, Urgent, Planned or Opportunity, and
- the *outage* requests overlap for any length of time, and
- the *outage* requests have a status of Submitted, Study, Negotiate, At Risk, Advance Approved, or Implemented, and
- the *outage* request periods share the same equipment and have constraint codes that are flagged to be in conflict with each other as shown in Table 3-3 below:

Table 3-3: Outage Request Constraint Code Conflicts

	OOS	IS	DRATE	HOLD OFF	MUST RUN	BTCT	PROT OOS	BF PROT OOS	*AVR*/PSS OOS	ASP OOS	INFO	ABNO
OOS		X										X
IS	X											X
DRATE												
HOLDOFF												
MUSTRUN												X
BTCT						X						
PROT OOS							X					
BF PROT OOS								X				
AVR/PSS OOS									X			
ASP OOS										X		
INFO												
ABNO	X	X			X							X

In addition to the conditions described above, *outage* requests that meet any of the following conditions will also be considered to be in conflict:

- The *outage* request's equipment are on the same undesirable *outage* combination, or
- UFLS validation fails, or
- *Outage* requests with BF PROT OOS constraint codes are overlapping at the same stations.

For example,

If…	Then…
Outages for **Line 1** A PROT OOS and **Line 1** B PROT OOS overlap	The *outage* management system will display a conflict
Line 1 A PROT OOS and **Line 2** B PROT OOS overlap	The *outage* management system will NOT display a conflict

3.2.4 Conflict Checking

The *outage* planning guidelines and conflicting constraint codes are embedded in the *outage* management system. If a submitted *outage* request is in conflict with another *outage* based on these criteria, the tool will display:

- An error message that the *outage* is in conflict,
- ID number of the *outage*(s) it is in conflict with (details regarding the conflicting *outage* are classified as *confidential information* and will be visible to *market participants* based on viewership rights), and
- Requirement to provide a rationale for the conflict to be allowed (details on conflict rationale are provided below).

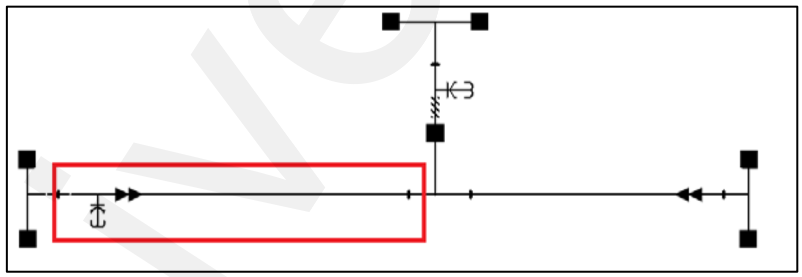
Market participants may determine the planned times of the conflicting *outage*(s) (either via the *outage* ID number or by contacting the *IESO*) and reschedule the *outage* to avoid the conflict.

Conflict Rationale

Outage requests having conflicts may be submitted as long as *market participants* provide a rationale for doing so. A complete rationale is required for the *IESO* to consider the *outage* – that is, for clearance the *market participant* must identify how the pieces of equipment are related, physical proximity, and the reason why other control actions are not available. Table 3-4 below lists criteria for the *IESO* to consider *outage*s based on conflict rationale.

Table 3-4: Criteria for Conflict Rationale Acceptance

***Advance Approval* Process**	**Acceptable Conflict Rationale Description**	**Examples**
Quarterly *Advance Approval* process	Only non-discretionary rationale will be accepted	• Clearance • Degradation of protection or cooling • Vacuum building *outage*

Advance Approval Process	Acceptable Conflict Rationale Description	Examples
Weekly, 3-Day and 1-Day *Advance Approval* processes	Discretionary rationale may be considered provided there is valid justification	• Favourable Ambient Conditions/Short Duration: the reason for the *outage* conflict is for thermal concerns, but the *outage* is scheduled overnight during lower load conditions. • Pre-contingency Control Actions: transfer load to alleviate thermal concerns or reconfigure *transmission system* so the contingency sheds load by configuration. • Partial Equipment *Outages*: Situations when only certain sections of the line are being taken out of service as shown in the diagram below, where the path critical to the transfer of  power is not interrupted. • Short Recalls: Conflicts for post-contingency concerns may be resolved by recalling the *outage* within 15 minutes.
Real-time process	Conflicts will only be considered for forced and urgent *outages*	• Forced *outage* to equipment for safety or environmental concern

The *IESO* will evaluate submitted rationale on a case-by-case basis and determine whether to allow the conflict to proceed or require the *market participant* to reschedule.

If the rationale does not meet the criteria described above and is deemed insufficient, the *IESO* will notify the *market participant* to reschedule the *outage*.

3.2.5 IESO Reports

The *IESO publishes* near-term and long-term reports to assist *market participants* in scheduling their *outage*s when they are more likely to receive approvals:

- **Near-term reports**: *Adequacy* Reports and Transmission Facility All in Service Limits Reports and Transmission Facility Outage Limits Reports contain *demand* forecasts and assessments for Ontario and are published by the *IESO* for informational purposes. Refer to Market Manual 7.2: Near-Term Assessments and Reports for further details on these reports.
- **Long-term report**: As per the *market rules*, the *IESO* prepares and *publishes demand* forecast, and a *security* and *adequacy* assessment for an 18-month period, on a quarterly basis (*MR* Ch. 5, Sec. 7.1.1.4 and 7.3.1.2). Refer to Market Manual 2.11: Reliability Outlook and Related Information Requirements for further details on this report.

3.3 Outage Coordination for Capacity Exports

A Capacity Seller[10] may have obligations with respect to the coordination of *outages* under applicable agreements with external *control areas*. Any such obligations are between the Capacity Seller and the external *control area* or capacity buyer, and are in addition to the obligations that the Capacity Seller has pursuant to the *market rules* and *market manuals*.

The *IESO* will continue to review *outage* requests in accordance with this *market manual*. Any additional review of *outages* by the external *control area* pursuant to the applicable agreements is independent of the *IESO's* review.

All *outages* and/or derates to a Capacity Resource that have partially committed capacity will be applied proportionally between capacity committed to the external *control area* and the *IESO-administered markets*. For example, where there is an *outage* to a Capacity Resource that has committed a portion of its capacity to an external *control area* (e.g., 30% of installed capacity), the *IESO* will assess impacts to *adequacy* based on the uncommitted capacity portion (i.e., remaining 70% of installed capacity).

3.3.1 Capacity Seller Requirement to Coordinate with Transmitters Prior to IESO Involvement

Refer to Market Manual 13.1: Capacity Export Requests, Section 3: Capacity Seller Requirement to Coordinate with Transmitters for information and requirements relating to coordination with *transmitters* regarding *outages* when submitting a *capacity export request* and prior to a Commitment Period.

Should a *planned outage* to transmission facilities arise whereby a Capacity Resource would be rendered Grid-incapable during a Commitment Period, the *IESO* may reject or revoke the *planned outage* provided certain conditions are met, including the Capacity Seller having demonstrated that it has made best efforts to work with the *transmitter* to reschedule the *planned outage*. In order to demonstrate to the *IESO* that best efforts have been made in the event such circumstances arise, a Capacity Seller must communicate with the applicable *transmitter* as described in Section 3 of Market Manual 13.1, and as set out below. The following explains the general process that the Prospective Capacity Seller should follow with the *transmitter* during the Commitment Period to demonstrate to the IESO that best efforts have been made to reschedule a planned outage should such circumstances arise:

1. Schedule a meeting (or multiple meetings, if necessary) in which it notifies the applicable *transmitter* of any capacity export commitments and determines if there are existing *planned outages* (unapproved or approved) that would render the Capacity Resource Grid-incapable at any time during the proposed Commitment Period.
2. Update the *outage* request (visible to the applicable *transmitter*)[11] in the *IESO*'s CROW system submitted in accordance with Market Manual 13.1, Section 3 with an information priority code, indicating the details of any capacity export commitments.

[10] Capitalized terms in this section are defined in Market Manual 13.1: Capacity Export Requests, Appendix A: Glossary of Capacity Export Terms.

[11] To setup Third Party Viewership in CROW which makes *outage* requests visible to the applicable *transmitter*, the Equipment Registration Specialist (ERS) must follow the steps outlined in the Online IESO Guide for all Contract Roles.

3. Throughout the Commitment Period, continue to check with the *transmitter* by, among other things, monitoring the CROW system, to determine if there are any *planned outages* during the proposed Commitment Period that would render the Capacity Resource Grid-incapable.
    a. Should there be *planned outages* during the proposed Commitment Period that would render a Capacity Resource Grid-incapable for, work with the *transmitter* to address the conflict, for instance:
        i. The *transmitter* may agree to reschedule the *planned outage*.
        ii. The *transmitter* may accept the risk of potential rejection or revocation of the *planned outage* in the event that it is determined that the *planned outage* will, during the Commitment Period, pose an unacceptable risk of an *adequacy* shortfall to the external *control area*.
4. Whenever applicable, update the applicable *outage* request with the information priority code indicating any changes or new information, including the resolution of any conflicting *outages* that may arise.

3.3.2 Capacity Seller Requirement to Coordinate with Transmitters Requiring IESO Involvement

If the *IESO* is advised by the Capacity Seller that the external *control area operator* has determined that a *transmitter's planned outage* that would render a Capacity Resource Grid-incapable would result in an unacceptable risk of an *adequacy* shortfall to the *external control area* and the *transmitter* and Capacity Seller are not able to come to an agreement to reschedule the *planned outage*, the Capacity Seller must contact the *IESO*. The *IESO* will assess whether the Capacity Seller has used its best efforts to reschedule the *planned outage* with the *transmitter* and whether any *reliability* concerns will arise if the *transmitter's planned outage* is rejected or revoked.

Examples of transmission *outages* necessary for *reliability* include, but are not limited to:

- Transmission *outages* that would prevent a future *forced outage* from occurring (e.g., a load supplied by a single transformer or line that would be forced out-of-service due to equipment concerns).
- Transmission *outages* that would leverage opportune generation and load profiles (e.g., matching *outages* with seasonal generational support).
- Transmission *outages* that would restore instantaneous protections and respective communication mediums.

If the *IESO* determines that the *outage* is for *reliability* purposes, the *IESO* will advise the Capacity Seller who may inform the external *control area* operator.

If the *IESO* determines that best efforts have been made and there is no *reliability* concern, the *IESO* may reject or revoke the *planned outage* pursuant to *Market Rules* Chapter 5, Section 6.4. The *IESO* will not, pursuant to this section, recall *outages* to facilitate *called capacity exports* or reject or revoke *forced outages* or urgent *outages*, or *outages* that bottle a resource's[12] output.

[12] The resource is operating to a reduced maximum generation output due to constraints resulting from transmission element outages. This does not include constraints that limit the resource to 0 MW output.

3.4 Outage Submission

Market participants submit *outage*s through the *outage* management system and the *IESO* uses that tool to confirm receipt and communicate approval back to the *market participant*. *Market participants* access the *outage* management Application Programmatic Interface (API) either through:

- The *IESO*'s web link located in the *IESO* Portal, or
- Their own *outage* management program.

Typically, an *outage* request will include the following information[13]:

Table 3-5: Information Requirement during Outage Submission

Name of Field in the Tool	Information To Be Provided by Market Participants
Applicant	The *market participant* that is submitting the information.
Single Point of Contact (SPOC)	The request will identify a SPOC for the *market participant*, either an individual or a position, along with sufficient information to enable effective communication with that SPOC (such as phone, fax, or email). For *market participants* with direct input to the *outage* management system, contact information for responsible parties will be on file with the *IESO*.
Priority Code and Purpose Code	Each *outage* request must contain appropriate Priority and Purpose Codes. See Section 2 for more details.
Purpose Description	General information about the *outage*, such as a brief description of the purpose and specific requirements or information pertinent to the *outage* (for example "Loading levels for a *generation facility* test"). Any regulatory requirements for an *outage* must be included in this information.
Request Weekly AA	For non-critical or low impact equipment, indicate if the *outage* is submitted under the Weekly *Advance Approval* process.
Requested Equipment	Sufficient information must be provided to identify and describe, if required, the specific piece of equipment, using the equipment identification and location confirmed by the *IESO* in Market Manual 1.2: Facility Registration, Maintenance and De-Registration.
Planned Start and End Date/Time	The submission must include the requested start date, start time, end date and end time.
Maximum Recall Time	The submission must include recall time, which is the total amount of time that would be required to return the equipment to service upon a request by the *IESO*. *Market participants* may submit optional comments to the *IESO* to provide more information.

[13] Refer to the "Outage Management System CROW OCSS Web Client User Guide" for detailed instructions on how to submit an *outage* request.

Name of Field in the Tool	Information To Be Provided by Market Participants
Recurrence	This information will describe the periodic nature of the *outage*, that is, whether the *outage* is continuous, continuous except for weekends, daily, etc.
Constraint Code	Each piece of equipment on the *outage* request must contain a constraint code to specify the equipment limitations. This will be based on the status of the equipment when the *outage* is implemented (for example: OOS, IS, MUSTRUN). See Section 2.4 for more details.
Equipment Description (Mandatory for Constraint Codes specified in Table 2-4 and Equipment Classes specified in Table C-1.)	General information about the equipment, such as a brief description of the status and condition of the equipment pertinent to the *outage* (for example "*Generation facility* unavailable for Black-start"). Any regulatory requirements for an *outage* must be included in this information.
MW Impact	Indicate the impact, if any, on real power resources which will result from the *outage*. This would be the direct impact associated with the specific piece of equipment rather than an indirect impact.
MVAR Impact	Indicate the impact, if any, on reactive power resources that will result from the *outage*. This would be the direct impact associated with the specific piece of equipment rather than an indirect impact.
Conflict rationale	This information will be used by the *IESO* to verify the importance of scheduling the *outage* in case of conflicts. **Note:** This field will not be visible to *market participants* with third party viewership.
Market participant to *IESO* Comments	• *Market participants* shall use this section to notify the *IESO* of any additional information, including details of their assessment, associated *outage* requests, switching details, etc. • *Generation facilities* shall also use this section to notify the *IESO* of any intent to arrange for replacement *energy* in the form of imports (*MR* Ch. 5, Sec. 6.3.6). When these arrangements are finalized, *market participants* shall provide the following information: o The MW amount and duration, o The *intertie zone* or zones through which the replacement *energy* is intended to be scheduled, o The *boundary entity* that shall submit the *offers* and schedule the replacement *energy* if dispatched by the *IESO*, and o Information regarding the e-Tag associated with the import, including a unique identifier, tag ID or tag format to be used. Refer to Section 5 for details on arrangement of replacement *energy*.

Name of Field in the Tool	Information To Be Provided by Market Participants
	Note: This field will not be visible to *market participants* with only third party viewership access.
Low-impact Questions	Based on the information submitted, *market participants* may be required to answer a few low-impact questions. This is to determine if the *outage* is eligible for 1-Day AA Auto AA, and/or FAA, as explained in Sections 2.7.5, 2.7.6 and 2.7.7, respectively. Refer to Appendix D – Column D in the table lists the questions that will be asked to *market participants*.

3.5 Outage Assessment

An *outage* request is assessed for its potential impact on the *reliability* and/or operability of the *IESO-controlled grid* with respect to the following:

- Reductions in system operating limits, *interconnection reliability* operating limits or changes in power transfers which encroach on a system operating limit,
- Will or is reasonably likely to have an adverse impact on the reliable operation of the *IESO*-controlled grid,
- Operating limits available and adequate monitoring tools available,
- Adequate system and area reserve,
- Adequate pre/post contingency assessment, voltage levels, islanding concerns, equipment limits and control actions,
- Adequate *ancillary services* requirements,
- System (global) and *local area adequacy* – capacity and *energy*,
- High-Risk or Emergency Operating State conditions, and
- Duplicated supply facilities including *station service* supply and protection systems

Refer to Market Manual 7.4: *IESO*-Controlled Grid Operating Policies for more details on the *IESO*'s *reliability* assessment. The *IESO* may provide details of their assessment under the '*IESO* to *Market Participants* Comments' field in the *outage* management system.

Note: This field will not be visible to *market participants* with only third party viewership access.

3.5.1 Market Participant Updates

Market participants may update an *outage* request while it is being assessed by the *IESO*. Changes other than the purpose description or comments require notification to the *IESO* by telephone. The *IESO* will assess the impact of the change. Revised *outage* requests will be assessed within the original study period.

If the update is …	The IESO shall…
An **insignificant** change as explained in Section 2.2.1	Allow the *market participant* to update the request.
A **significant** change as explained in Section 2.2.1	Allow the *market participant* to update the request and revise the priority date.

3.5.2 Outage Assessment Outcomes

Table 3-6 below describes the next steps and associated obligations following the *IESO*'s assessment of *outage*s.

Table 3-6: Outage Assessment Outcomes and Next Steps

***IESO* Assessment Outcomes**	**Possible Next Steps**	**Associated Obligations**
Provide *advance approval* (as per timelines in Section 2.7)	Final Approval	On the day of the *outage*, *market participants* must contact the *IESO* Control Room via telephone when they are ready to proceed with the *outage*. The *IESO* will, in general, provide final approval to a *planned outage* unless it foresees an adverse *reliability* impact, based on ongoing *security* and *adequacy* assessments. When requesting final approval, *market participants* should give due consideration to any adjustments to generation patterns or system configuration required by the *IESO* prior to removal of equipment from service and the time required to effect these adjustments (*MR* Ch.5, Sec. 6.4.3.3). *Outages* that are eligible for FAA will be automatically granted Final Approval at the beginning of the planned start date of the *outage*.
	Revocation	*Market participants* have the option of resubmitting or canceling the *outage*. The *IESO* will work with *market participants* to re-schedule the *planned outage* to a date and time at which the *outage* will not likely have an adverse impact on the *reliability* and/or operability of the *IESO-controlled grid*. Where practical, the *IESO* will consider date and time preferences of *market participants* when re-scheduling the *outage* (*MR* Ch. 5, Sec. 6.4.10). The original priority date is maintained if *market participants* re-submit the *outage* within five *business days* of being revoked (*MR* Ch. 5, Sec. 6.4.10).
	Outage Start Delays	*Market participants* must inform the *IESO* if they expect their *outage* to be delayed from starting as scheduled and whether the delay is expected to result in a planned extension. • Start of *outage* delayed by 30 minutes or less: *Market participants* must notify the *IESO* Control Room by telephone. • Start of *outage* delayed by greater than 30 minutes: *Market participants* must notify the *IESO* Control Room by telephone and update their *outage* request.

IESO Assessment Outcomes	Possible Next Steps	Associated Obligations
	Planned Extension	*Market participants* must submit requests for planned extensions as a new *outage* request. The new request must reference the *outage* ID of the on-going *planned outage* in the *outage* management system. The *IESO* will review planned extension requests on a reasonable effort basis if the *outage* request was scheduled to start and end on the same day. Otherwise the planned extension will be treated as a late submission and either rejected or revoked. The *IESO* will reject the request for planned extension if it is determined that the extension is likely to adversely impact the *reliability* and/or operability of the *IESO-controlled grid* or is likely to require the rescheduling, recall or revocation of a *planned outage* request previously submitted to the *IESO* (*MR* Ch. 5, Sec. 6.4.8). In such cases, *market participants* shall ensure the *outage* duration does not exceed the originally approved *planned outage* or the period as advised by the *IESO* when rejecting the *outage* request (*MR* Ch. 5, Sec. 6.4.8).
Negotiate to reschedule	Reschedule *outage* for *advance approval*	*Market participants* must reschedule the *outage* following discussions with the *IESO*. The priority date of the original *outage* request will be retained during resubmission if completed within study timeframe.
	Cancellation	*Market participants* must cancel the *outage* request in the *outage* management system.
	Rejection (for *outages* submitted under the Weekly, 3-Day or 1-Day *Advance Approval* processes)	The *IESO* will provide *market participants* with the reason for rejection, subject to applicable confidentiality restrictions. *Market participants* may submit a new *outage* request. Original priority date will be retained if resubmitted within five *business days* and it was the first time that the *outage* was rejected (*MR* Ch. 5, Sec. 6.4.17). If these conditions are not met, the re-submitted *outage* request will receive a new priority date.

IESO Assessment Outcomes	Possible Next Steps	Associated Obligations
	'At Risk' (for *outages* submitted under the Quarterly *Advance Approval* process)	The *IESO* will provide *market participants* with the reason for placing the *outage* 'At Risk', subject to applicable confidentiality restrictions. *The IESO* will review the *outage* during the next Quarterly, Weekly, 3-Day or 1-Day assessment window, as explained in Section 2.7.2. *Market participants* may choose to re-submit *outages* placed 'At Risk.' Refer to Section 2.7.2 for criteria for retaining original priority for re-submitted *outage* requests.

3.6 Outage Implementation

Outages that have received final *advance approval* from the *IESO* can be placed into implementation. *Market participants* are required to notify the *IESO* Control Room to confirm that the *outage* has commenced (*MR* Ch. 5, Sec. 6.4B.1) by providing actual start times through *outage* management system, unless otherwise determined by the *IESO*.

If…	Then…
After implementation, the *market participant* wishes to adjust the actual start time of the *outage*	• The *market participant* must call the *IESO* Control Room and request that the *IESO* clears their implementation and must provide the reason for the change. • The *IESO* will assess the validity of the request and if approved, transition the *outage* to 'Final Approved' status which will delete the actual start time. • The *market participant* must input the adjusted actual start time in the *outage* management system and transition the *outage* from 'Final Approved' to 'Implemented' status.

3.6.1 Planned and Forced Extensions

Market participants have the option of forced extensions, in cases where personnel safety or equipment damage may result. However, forced extensions for planned work will be reviewed for possible violations of the *market rules*. Forced extensions to planned or forced *outages* must be electronically updated in the *outage* management system by *market participants* and communicated via telephone to the *IESO* Control Room. If the forced extension is identified by 15:00 EST, one *business day* prior to the planned end time of the *outage*, *market participants* shall, on a reasonable effort basis, also communicate the forced extension to the *IESO* Market Forecasts & Integration department.

Planned extensions to *planned outages* must be submitted as new *outage* requests.

3.6.2 Recall

Any time during implementation, the *IESO* may recall either the current period or the entire *outage*, based on sudden or unexpected impacts to the *reliability* and/or operability of the *IESO-controlled grid*. The *IESO* will provide affected *market participants* with the reason for the recall. Details regarding *market participant* compensation in cases of *outage* recall are provided in Section 3.8.

Market participants will be expected to meet the recall times specified in the original submission for the *planned outage*. No *outage* will be recalled unless the *IESO* has revoked or rejected all other *planned outages* that have not yet started and which could eliminate the need to recall the *outage* already in progress (*MR* Ch. 5, Sec. 6.4.11).

Generation facilities have the option to arrange for replacement *energy* to preclude being recalled. Further details on replacement *energy* are provided in Section 5.

3.7 Outage Completion

Market participants are required to (*MR* Ch. 5, Sec. 6.4A):

- Notify the *IESO* by telephone when either the current period or the entire planned or *forced outage* has been completed,
- Request *IESO* approval by telephone to return equipment to service before doing so,
- Receive *IESO* approval to return the equipment to service. The *IESO* will notify *market participants* at this time if they wish to direct the operation of equipment to return it to service, and
- Notify the *IESO* when equipment that was the subject of a planned or *forced outage* has been fully restored to service by providing actual end times through the *outage* management system, unless otherwise determined by the *IESO*.

If…	Then…
After completion, the *market participant* wishes to adjust the actual end time of the *outage*	• The *market participant* must call the *IESO* Control Room and request that the *IESO* clears their completion and must provide the reason for the change. • The *IESO* will assess the validity of the request and if approved, transition the *outage* to ‘Implemented’ status which will delete the actual end time. • The *market participant* must input the adjusted actual end time in the *outage* management system and transition the *outage* from ‘Implemented’ status to ‘Completed’ status.

3.8 Outage Compensation

Generation facilities, *distributors* and *wholesale customers* whose *planned outages* are revoked or recalled by the *IESO* are entitled to compensation for expenses associated with the revocation or recall, subject to the following conditions (*MR* Ch. 5, Sec. 6.7.2):

- the *outage* was originally provided *advance approval* by the *IESO*,
- the *outage* was recalled or had *advance approval* revoked because of a material error in the *IESO*’s *demand* forecast, a failure of *generation facilities* within the *IESO control area*, a failure of facilities forming part of the *IESO-controlled grid*, or a failure of *interconnection* facilities, and
- the out-of-pocket expenses exceed $1,000.00.

Under the *market rules*, only out-of-pocket costs are eligible for compensation. These are sunk costs that are unrecoverable and will be incurred again by *market participants* in order to complete the *outage*. Items such as overtime costs and equipment rentals are eligible.

Market participants, whose Quarterly, Weekly or 3-Day *Advance Approval* for a *planned outage* on a *generation facility* is initially granted and then revoked by the *IESO*, will not be eligible for compensation if (*MR* Ch. 5, Sec. 6.7.3A):

- The *IESO* revoked the *advance approval* due to a *forced outage* of another *generation facility* with the same *registered market participant* as the *generation facility* that submitted the *planned outage* request and the *forced outage* occurred before 16:00 EST three *business days* prior to the scheduled start of the *planned outage*, or
- The *IESO* revoked the *advance approval* due to delayed return to service from a planned or *forced outage* of another *generation facility* with the same *registered market participant* as the *generation facility* that submitted the *planned outage* request, or
- A *planned outage* is granted Quarterly *Advance Approval* and scheduled to start in the last three months of a six month coverage period, and the *IESO* revokes the Quarterly *Advance Approval* before the end of the next quarterly study period.

Example A: Market participant NOT entitled to compensation

As shown in Figure 3-1 below, the *outage* is scheduled for May and receives Quarterly *Advance Approval* in November. The *IESO* revokes quarterly approval in January. In this case, the *market participant* is not entitled to compensation because the revocation is done before the next quarterly study period ends in February.

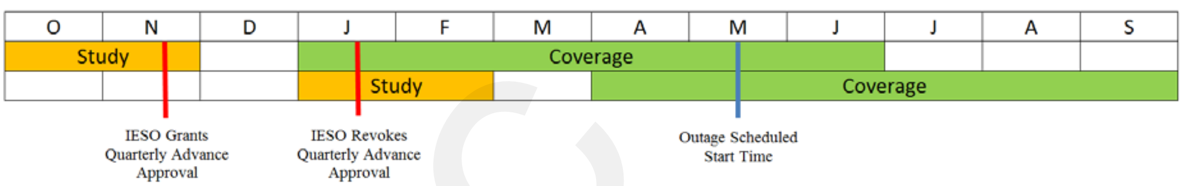


Figure 3-1: Compensation Eligibility – Example A

Example B: Market participant entitled to compensation

In this example, the *outage* is scheduled for May and the *IESO* revokes Quarterly *Advance Approval* in March (i.e. after the next quarterly study period ends in February). Therefore the *market participant* is entitled to compensation.

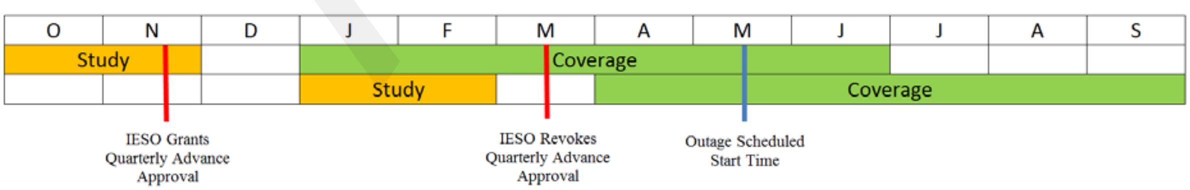


Figure 3-2: Compensation Eligibility – Example B

Example C: Market participant entitled to compensation

In this example, the *outage* is scheduled to start in March which is within the first three months of the quarterly coverage period, therefore even though the *IESO* revokes the *outage* before the end of the next quarterly study period in February, the *market participant* is entitled to compensation.

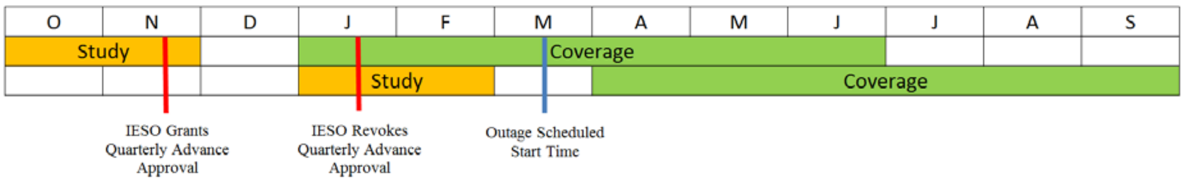


Figure 3-3: Compensation Eligibility – Example C

Generation facilities whose *planned outages* have *advance approval* revoked or are recalled even though they had successfully arranged for replacement *energy*, are eligible for compensation. However, the *generation facility* will not be eligible for compensation for any lost opportunity costs associated with the import *energy* that was secured through the arranged replacement *energy*.

Claims for compensation must be submitted using the "Request for Outage Compensation" (IMO_FORM_1350) that is available on the *IESO*'s website (See Appendix A), and substantiated by receipts or statements detailing each line item. These claims will be subject to audit and verification by the *IESO*.

Transmitters are not entitled to compensation for any costs, losses or damages associated with the revocation or recall of a *planned outage* (*MR* Ch. 5, Sec. 6.7.1).

Each act of revocation or recall by the *IESO* shall be treated separately for compensation purposes (*MR* Ch. 5, Sec. 6.7.7).

– End of Section –

4. Outage Reporting Requirements

This Section 4 outlines *outage* reporting requirements that are specific to certain classes of *market participants* when submitting *outage* requests to the *IESO*, unless granted *exemption*. Each sub-section provides sample Priority, Purpose and Constraint Codes that *market participants* may use when submitting *outage* requests via the *outage* management system. For detailed description of these codes, refer to Sections 2.2, 2.3, and 2.4. Refer to Section 2.6 for a mapping of these codes.

Note: The rules for submission, approval and determining priority as per *market rules* are applicable for all *outage* requests.

4.1 Generation Facilities

Aggregated *generation facilities* are required to report *forced outages*, unit limitations, deratings, de-staffing and any change in status that affects the maximum output of a *generation unit*, the minimum load of a *generation unit*, or the availability of a *generation unit* to provide *ancillary services* such as *regulation*, *operating reserve*, voltage support, *black start capability* or must run contracts (*MR* Ch. 5, Sec. 3.6.1).

4.1.1 Deratings

All *generation facility* deratings, including those resulting from *generation facility* start-up or shutdown, are required to report *outage*s in the following circumstances:

- Any planned or forced material reduction in *generation facility* output that causes a derating equal to the greater 2% of rated output or 10 MW,
- A component failure, operational limit or other circumstance that will cause the unit to trip if no control actions can be taken before the condition can be repaired as assessed by the *generation facility*, and
- A new potential change in unit/plant condition that can cause the loss of multiple units at its *facility* based on its internal assessment/forecast.

A *generation facility* wishing to ramp down for a *planned outage* is required to follow either of the following methods:

- Submit and get approval for a *planned outage* request**.** The *generation facility* will be ramped down at the submitted ramp rate in advance of the hour in which the *outage* commences, or
- Submit derate requests electronically to reflect the capability of the *generation facility* as it ramps down.

Normal loading delays during a *generation facility* start-up are not considered a derating if the *generation facility* is able to ramp towards full load without significant holds. Where a *generation facility* must hold at a specific load for greater than 30 minutes during start-up, this should be considered a derating. The *IESO* will assess planned deratings required to support a *generation facility* ramp down or start-up on a reasonable effort basis.

If fossil *generation facilities* having known start-up delays are scheduled by pre-*dispatch* within a timeframe that does not accommodate the start-up delay, *market participants* are required to cancel their *offers* for the hours in which their units are unavailable. Within the restricted and mandatory windows, the *IESO* Control Room shall allow these *offers* to be removed.

A *generation facility* whose *outage* or derating results in a change of the greater of 2% of rated output or 10 MW, is not required to revise their *offers* if the derating/*outage* is expected to last less than two hours. Where their *offer* had been altered to reflect the capability of their resource, a quantity change or new *offer* will be allowed by the *IESO*. This change should reflect the capability of the resource in the pre-*dispatch* schedule. Changes to *offers* in the mandatory and restricted window will not affect the current hour.

Market participants are required to use the DRATE or MUSTRUN Constraint Code when submitting *outage* requests, Table 4-1 provides an example:

Table 4-1: Example Codes When Submitting Planned Derate Requests

Priority Code	Constraint Code	Purpose Code
Planned	DRATE	Maintenance

4.1.2 Tests

Generation facilities may request approval for an Opportunity *outage* to conduct tests during a planned or *forced outage*. In order for the *outage* requests and tests to not have conflicting time spans in the *outage* management system, the following procedure should be followed:

- Revise the end time of the original *outage* request to coincide with the start of the first test.
- Ensure the first test request has a start time that corresponds to the end time of the *outage* in the revised *outage* request.
- Create a second *outage* request to accommodate all the *outage* time required in the original *outage* request and has a start time corresponding to the end time of the first test request. The end time corresponds to the end time of the original *outage* request, or
- Subsequent pairs of *outage*/test requests with matching start/end times to cover all the remaining tests as required.

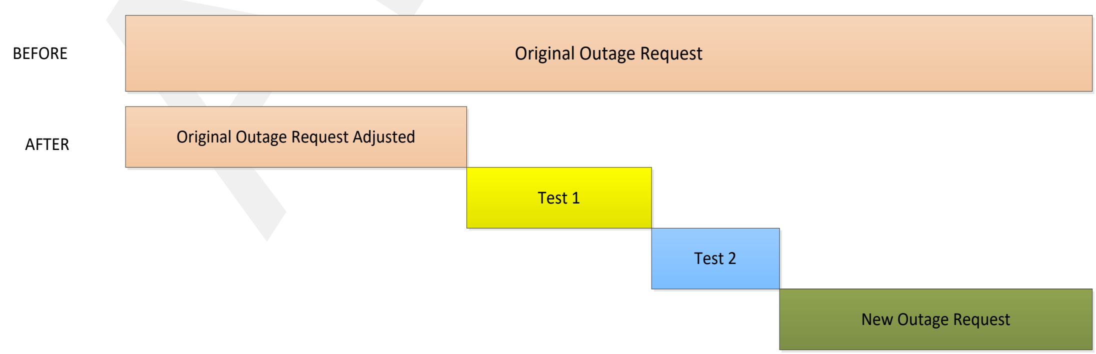


Figure 4-1: Submitting Test Request during Outage

Where testing is extensive and is expected to continue for a minimum of two days, *market participants* may request that the *IESO* treat the *generation facility* as a *commissioning generation facility* (*MR* Ch. 7, Sec. 2.2A). Requests to be treated as a *commissioning generation facility* should be made to the *IESO* through the *outage* process and to Facility Registration. Requests of this nature should be made with a minimum of six *business days*' notice. See Section 4.1.3 for reporting details.

For tests of hydroelectric *generation facilities* within an aggregate, *market participants* must submit a test profile as part of the *outage* request. The aggregate will be offered to reflect the aggregate output during testing. The aggregate total generation will be maintained at the offer/*dispatch* level as the test *generation facility* loads or unloads.

Market participants having aggregate units with one of the units being tested would offer, ensuring that the associated price is appropriate to be scheduled, the maximum achievable output for the aggregate, excluding the testing unit and compensate for testing by adjusting units within the aggregate. Non-aggregated *generation facilities* are required to offer the full capability of the *facility* and use *outage* requests to derate the *facility* to the appropriate test level (*MR* Ch. 5, Sec. 6.6.7).

Often *generation facility* tests are conducted where the test can be suspended and the *generation facility* is then capable of re-loading. These tests are treated differently than *generation facility* deratings in that no *outage* for a derating is required, however *market participants* are required to submit an *outage* request in accordance with the submission deadlines outlined in Section 2.7 indicating the planned test quantities as described in the example below.

For any hour in which a *market participant*'s *generation facility* is expected to undergo a test, *market participants* must submit an economical *offer* for the generation that equals the expected hourly average *energy* delivery of that generating unit.

Example:

If expected generation is…	**Then the *offer* submitted for the hour will be…**
250 MW for 20 minutes, 175 MW for 10 minutes, and 135 MW for 30 minutes	$\frac{250*20 + 175*10 + 135*30}{60}$ = 180 MW at an *offer* price that would ensure the unit is scheduled to deliver 180 MW

However, since the unit is testing, it would not move to the *dispatch* target, and the *IESO* operator may have to intervene to adjust for the behaviour of the testing unit.

Where the test is instantly recallable, *generation facilities* are allowed to participate in the *operating reserve market*. This is acceptable as long as the *market participant* offers the *energy* as outlined above (and below) and if the *market participant* ensures that the *operating reserve* quantity offered each hour meets the following criteria:

(maximum *energy* expected to be produced during the hour) + (*operating reserve* quantity offered during the hour) = (maximum amount that the unit can produce that hour)

Using the example above:

If…	The *offer* submitted for the hour will be…
Maximum generation per hour is 450 MW	180 MW at a price to ensure that unit is scheduled 200 to 270 MW of *energy* at a higher price.

This *energy offer* would be scheduled if *operating reserve* is activated or if there are a shortage of resources that required the *energy* (at which time, the *market participant* would be expected to abandon the test to meet their operating reserve dispatch).

Generation facilities whose test *outage*s are immediately recallable and participate in the *operating reserve market* are not expected to submit for compensation costs. Rather, it is expected that *offers* for *energy* and *operating reserve* will reflect any compensation for interrupting the test.

For tests of aggregate *generation facilities* with immediate recall, *market participant*s must provide a test profile via an information request to the *IESO*. *Market participants* must offer the aggregate as per the *energy* they desire to run but would adjust loading of units within the aggregate to obtain the required test levels. *Market participants* must request approval to synchronize and desynchronize the test unit, but may change the test unit MW as desired while maintaining the aggregate MW as offered.

Market participants are required to use the Testing Purpose Code when submitting *outage* requests, Table 4-2 provides an example:

Table 4-2: Example Codes When Submitting Planned Testing Requests

Priority Code	Constraint Code	Purpose Code
Planned	IS	Testing

4.1.3 Commissioning Facilities

A *commissioning generation facility* shall be treated as a *self-scheduling generation facility* for the purposes of *outage* coordination and shall follow the normal *outage* scheduling process (*MR* Ch. 7, Sec. 2.2A). The *commissioning generation facility* shall provide a detailed test plan including the following information, but not limited to:

- The expected time of synchronizing to or de-synchronizing from the *IESO*-controlled grid,
- *Energy* and reactive output levels,
- The timing of and ramp rates associated with changes in *energy* and reactive output levels,
- Run-back or trip tests for the *commissioning generation facility*, and
- Excitation and Power System Stabilizer (PSS) tests.

The *IESO* will attempt to provide scheduling flexibility for *commissioning generation facilities* in the same manner as those *generation facilities* performing routine testing as per Section 4.1.2. *Market* *participants*, whose *generation units* with *planned outages* are returning to service from long-term *outage*s, or are commissioning *generation units*, shall provide the *IESO* with a loading profile before synchronization.

The treatment of *self-scheduling generation facilities* in the *IESO*'s *security* and *adequacy* assessments depends on the type of commissioning being performed as follows:

1. New *generation facilities* or those returning from long-term *outage*s (mothballing) that are registered as *self-scheduling generation facilities* will be treated as unavailable for the purpose of calculating available capacity in the *IESO*'s *adequacy* assessments.
    - A *planned outage* request should be submitted by *market participants* that define first synchronization and the expected date of commercial operation.
    - *Market participants*, who are not *variable generation* facilities, should submit, and keep up to date, the expected commissioning schedule (either via an *outage* request or other format as specified by the *IESO*) for the duration of the commissioning period.
    - *Market participants*, who are *variable generation facilities*, must submit, and keep up to date the expected commissioning schedule via an *outage* request for the duration of the commissioning period.
    - *Commissioning generation facilities*, that are not *variable generation facilities*, should manage all commissioning activities, until commercial operation is declared, with the use of *offers* as a *self-scheduling generation facility*. These *offers* should reflect the most recent update to the commissioning schedule.
    - *Commissioning generation facilities*, that are *variable generation facilities*, shall offer a forecast output as provided by the *IESO*.
2. *Generation facilities* that are registered as *self-scheduling* generation *facilities* for the purpose of testing new or modified equipment associated with the *generation facility* will be treated as available for the purposes of calculating available capacity in the *IESO*'s *adequacy* assessments.
    - A *planned outage* request should be submitted by *market participants* that define the commissioning period.
    - While commissioning, *market participants*, who are not *variable generation facilities*, must manage their loading by the use of *offers* as a *self-scheduling generation facility*. *Market participants*, who are *variable generation facilities*, must manage their loading via *outage* requests and offer a forecast output, as provided by the *IESO*.
    - Outage requests are to be submitted for each stage of the commissioning period that reflects expected output.

For *generation facilities* beginning commissioning, the *IESO* requires at least three months advance notice of the expected synchronization date (*MR* Ch. 7, Sec. 2.2A.5). This date may be revised by *market participants* as required.

For the purpose of submitting *dispatch data*, the *commissioning generation facility* shall apply to register as a *self-scheduling generation facility* and comply with applicable *market rules*, in order to submit the necessary *dispatch data* for testing. Requests to be registered as a *self-scheduling generation facility* should be made to the *IESO* within a minimum of six *business days*' notice (*MR* Ch. 7, Sec. 2.2A). Any such registration for the purposes of commissioning tests shall expire on the completion of these tests, at which time registration as a *generation facility* is required to participate in the *real-time markets*.

Where the *generation facility* undergoing commissioning testing, forms part of an aggregate, the whole aggregate will be treated as *self-scheduling generation facility*. The *IESO* may not approve these requests where the loss of *operating reserve* from the aggregate causes a *reliability* concern (*MR* Ch. 7, Sec. 2.3.2).

In the event that the *commissioning generation facility* intends to increase its output above the *self-schedule offer* for any reason, the *offers* should be updated outside the mandatory window. If the *commissioning generation facility* is unable to achieve the *self-schedule offer* for any reason, the *offers* should be updated as soon as possible. An *outage* request should also be submitted to reflect the reduced capability from the *self-scheduled* quantity.

Market participants are required to use the Commissioning Purpose Code when submitting *outage* requests, Table 4-3 provides an example:

Table 4-3: Example Codes for Commissioning Generation Facilities

Priority Code	Constraint Code	Purpose Code
Planned	IS	Commissioning

4.1.4 Segregated Mode of Operation

Outage requests to operate *generation facilities* in *segregated mode of operation* (SMO) must be submitted by the 1-Day *Advance Approval* deadline, unless otherwise agreed to by the *IESO*. Along with submitting an *outage* request, *market participants* are also required to notify the *IESO* by telephone of the request being submitted.

The *IESO* must approve them, by telephone or the *outage* management system, no later than 10:00 EST, one *business day* prior to the SMO start date to ensure inclusion in first run of Day-Ahead Commitment Process (DACP).

DACP-related processes for *generation facilities* operating in SMO are detailed in Market Manual 9.2: Submitting Operational and Market Data for the DACP.

Market participants may submit SMO requests as opportunity *outages,* two hours prior to the start of the *outage*. The *IESO* will approve or reject the *outage* requests no later than 90 minutes prior to the implementation of the *segregated mode of operation*.

When submitting a request for operation in segregated mode, *generation facilities* must:

- Submit an *outage* request for their units for the duration of the segregated mode.
- Submit a second *outage* request for the time required to ramp down the units to zero (to be submitted within the hour prior to the start of the first *dispatch hour* to which the segregated request pertains).
- Maintain the *offers* for their *generation facilities* for each *dispatch hour* in which these facilities will or are intended to operate in *segregated mode of operation*[14].
- Notify the *IESO* by phone that the Request for Segregation was submitted (*MR* App. 7.7, Sec. 1.3.5).

[14]The submission of the *outage* request will fulfill the obligations with respect to the submission of *dispatch data* as set out in *MR*, CH. 7, App, 7.7.

Where a Request for Segregation will require *transmission system* elements to be reconfigured or removed from service, the *IESO* will notify the *transmitter* and enter an *outage* request in the *outage* management system to reflect this reconfiguration for the duration required to support the Request for Segregation.

When units are returning from *segregated mode of operation*, *generation facilities* must ensure:

- The *outage* for their units ends at the same time the units are to be reconnected to the *IESO*-controlled grid.
- Valid *offers* are in the *IESO* systems for these units, for the hour they will be returning from *segregated mode of operation*. When submitting their offers, *generation facilities* must respect the short notice submission criteria as specified in the *market rules*.
- If necessary, to zero their *revenue meter* while in *segregated mode of operation* in order to be removed from the *IESO*'s *settlements process*.
- Notify the *IESO* by phone of the request for de-segregation (*MR* App. 7, Sec. 1.3.3, and 1.3.4).

Market participants are required to use the Segregated Mode of Operation Purpose Code when submitting *outage* requests, Table 4-4 provides an example:

Table 4-4: Example Codes When Requesting Planned Segregated Mode of Operation

Priority Code	Constraint Code	Purpose Code
Planned	OOS	Segregated Mode of Operation (SMO)

4.1.5 Testing of Capacity Generation Resources

The *IESO* may direct *capacity generation resources* to perform up to two activation tests per *obligation period*, per *capacity obligation* allocated resource, to verify that the allocated *auction capacities* are deliverable. Tests will be scheduled to occur during the *availability window* of the *dispatch day*.

The tests are conducted as follows:

- At least one (1) *business day* in advance of any exercise, applicable *generators* will be contacted by the *IESO* for test details.
- In the day-ahead timeframe and prior to DACP, the resource will have a *constraint* applied to *generate* to the greater of either their (1) *capacity obligation or (2) minimum loading point for* the duration of at least their *minimum generation block run time (MGBRT)*.
- The *registered market participant* for the *facility* must ensure that *offers* are submitted related to the test.
- If a resource being tested demonstrates an injection of electricity into the *IESO-controlled grid* equal to or greater than their *capacity obligation* for the period of time with which it has a *constraint* applied to it to *generate,* the test will be deemed a success.
- Failure of the test will result in the applicable charges as specified in [Market Manual 5.5: Physical Markets Settlement Statements]().

If a *capacity generation resource* is unable to comply with the test activation of the *auction capacity* on the *dispatch day*, it is the responsibility of the *capacity market participant* to notify the *IESO*, according to the outage reporting requirements specified for *generation facilities* in this manual and update the *energy offers* in accordance with Market Manual 4.2. Subsequent test activation will be rescheduled by the *IESO* following the completion of the outage.

A test is deemed a success if the resource demonstrates an injection in *energy* that is equal to or greater than its allocated *capacity obligation*. The *IESO* may determine a test activation for a generation resource is not required if the:

- *capacity generation resource* receives and follows a *dispatch instruction* in the *energy market*,
- dispatch is based on the *energy offer*,
- dispatch is within the availability window, and
- *capacity generation resource* demonstrates that its allocated *capacity obligation* has been met.

Failure of a *capacity generation resource* to perform a successful test activation may result in one or more of the following:

- Non-performance charges as specified in [Market Manual 5.5: Physical Markets Settlement Statements](),
- A subsequent test activation to be scheduled by the *IESO*, or
- A compliance investigation to be performed by the *IESO*.

4.2 Loads

4.2.1 Dispatchable Loads

Dispatchable loads are required to submit information requests in the event of *planned outages* or tests that result in *demand* reduction of 20 MW or more relative to the average weekday *demand* of the *facility*. During an *outage*, loads are expected to consume according to their *bid* quantity. Upon change of plan, loads are expected to update *bid* and *offer* data and notify the *IESO*.

Any planned or forced *outages*, restrictions, deratings or changes in configuration of power system auxiliaries and transmission facilities operated at 50 kV or higher that form part of, or are, connected to the *IESO*-controlled grid and which affect the operation of the *dispatchable load*, must be submitted to the *IESO*. These *outage*s shall be coordinated and submitted by the owner of the *facility* required to be on *outage*. For *outage*s to the transmission element to which the *dispatchable load* is connected, the *transmitter* will apply for the *outage* and coordinate with the customer.

Table 4-5 provides example codes for *dispatchable loads* when submitting *planned outage* requests:

Table 4-5: Example Codes for Planned Outages to Dispatchable Loads

Priority Code	Constraint Code	Purpose Code
Planned	DERATE	Repair

4.2.2 Connected Wholesale Customers

Wholesale customers are required to notify the *IESO* in the event of changes that result in reduction of 20 MW or more from the average weekday *demand* or supply. This requirement applies, for example, to large industrial customers that periodically shut down their plants for maintenance, holidays, etc.

Wholesale customers are required to submit information about the planned shutdown in advance, however, approval from the *IESO* is not required, the *outage* is supplied for information purposes only.

Market participants are required to use the codes in Table 4-6 when submitting *outage* requests:

Table 4-6: Applicable Codes for Wholesale Customers

Priority Code	Constraint Code	Purpose Code
Information	INFO	Other

4.2.3 Distributors and Transmitters

Under the *market rules*, *distributors* are required to notify the *IESO* in the event of changes that result in change greater than 20 MW from the average weekday *demand* or supply. This requirement applies to *distributors* with embedded loads or generation that are not registered with the *IESO* (*MR* Ch. 5, Sec. 3.4.1, 3.5.2, and 3.7.1).

Distributors and *transmitters* are also required to notify the *IESO* in advance of *demand* control actions. Demand control actions include: *demand* management, voltage reductions and disconnections.

In the event of plans for *demand* control actions, *market participants* are required to submit *outage* information to the *IESO* by 10:00 EST each day, for the following day. Any *emergency* plans subsequent to this deadline must be submitted immediately.

The following information is required:

- Proposed date, time, and duration of the cuts by *connection point* on the *IESO-controlled grid*, by hour, and
- Proposed MW reduction of *demand* by *connection point* on the *IESO-controlled grid*, by hour.

The actual decrease in MW reduction of *demand* achieved through *demand* control actions must be communicated directly to the *IESO* Control Room, at the time that the reduction is implemented.

Table 4-7 provides example codes for *distributors* and *transmitters* when submitting *planned outage* requests:

Table 4-7: Example Codes for Distributors and Transmitters

Priority Code	Constraint Code	Purpose Code
Planned	OOS	Switching

4.2.4 Demand Response Resources with Capacity Obligations

This sub-section 4.2.4 outlines outage management requirements for *demand response resources* with *capacity obligations*.

I. Outages: Dispatchable Load Resources with a Capacity Obligation

Dispatchable loads associated with a *capacity obligation* will submit *outage* requests in accordance with *outage* reporting requirements and must update their *bids* to reflect the *demand response capacity* of the resource during the *outage*.

Market participants are required to use the codes in Table 4-8 when submitting *outage* requests:

Table 4-8: Applicable Codes for Demand Response Resources

Priority Code	Constraint Code	Purpose Code
Information	INFO	Other

II. Testing: Dispatchable Load Resources with a Capacity Obligation

The *IESO* may direct *dispatchable loads* resources associated with *capacity obligations* to perform up to two activation tests per *obligation period*, to verify that the registered *demand response capacity* of the resource is deliverable. Tests will be scheduled to occur during the *availability window* of the *dispatch day*, and resources are expected to demonstrate a reduction in *energy* withdrawal from the IESO controlled grid equal to or greater than the registered *demand response capacity* of the resource. The *IESO* will schedule the test activation and provide notification to *capacity market participants* one day in advance of the test.

If a *dispatchable load* resource associated with a *capacity obligation* is unable to comply with the test activation on the *dispatch day*, it is the responsibility of the *capacity market participant* to notify the *IESO*, update the *demand response energy bids* and submit an *outage* request for the resource. Subsequent test activations will be rescheduled by the *IESO* following the completion of the *outage*.

No compensation will be provided to these *capacity market participants* for any costs related to test activation conducted during an *obligation period*.

For *dispatchable load* resources, a test is deemed a success if the resource demonstrates a reduction in energy withdrawal that is equal to the allocated *capacity obligation*. The *IESO* may determine a test activation for a *dispatchable load* resource is not required if the:

- *dispatchable load* receives and follows a *dispatch instruction* in the *energy market*,
- dispatch is based on the *demand response energy bid*,
- dispatch is within *the availability window*, and
- *dispatchable load* demonstrates that the *capacity obligation* has been met.

The *IESO* may schedule test activation for *dispatchable load* resources regardless of whether the above conditions are met, if there is evidence that the resource is not able to deliver its *capacity obligation* at any time during the *obligation period*.

Failure of a demand response resource to perform successful test activation may result in one or more of the following:

- Non-performance charges as specified in Market Manual 5.5: Physical Markets Settlement Statements,
- A subsequent test activation to be scheduled by the *IESO*, or
- A compliance investigation to be performed by the *IESO*.

III. Testing: Hourly Demand Response Resources with Capacity Obligations

The *IESO* may direct *hourly demand response (HDR)* resources associated with *capacity obligations* to perform up to two activation tests per *obligation period*, to verify that the allocated *demand response capacity* of the resource is deliverable. Specifically, these tests are conducted by the IESO to assess an *HDR* resource's ability to demonstrate a reduction in *energy* withdrawal from the IESO controlled grid equal to or greater than the allocated *demand response capacity* of the resource. The *IESO* will provide notification to *capacity market participants* one day in advance of the test with the actual test itself occurring during the *availability window* of the *dispatch day*. Testing for *HDR* resources is conducted for four hours, unless an *HDR resource is* qualified for reduced test duration.

For test activations, *capacity market participants* with *hourly demand response* (HDR) resources will receive a standby notice on the *pre-dispatch day* and an activation notice approximately 2 hours and 30 minutes in advance (but no later than 2 hours in advance) of the first *dispatch hour* of the test activation. Resources will receive a schedule in pre-*dispatch* and real-time, regardless of the *demand response energy bid* price submitted.

If an *HDR* resource associated with a *capacity obligation* is unable to comply with the test activation on the *dispatch day*, it is the responsibility of the *capacity market participant* manage its non-performance as described in this Market Manual. If the non-performance event indicates that the entirety of the *HDR* resource's *demand response capacity* is unavailable, subsequent test activations will be rescheduled by the *IESO* following the completion of the non-performance event.

An *HDR* resource test activation is considered valid, unless:

- The *capacity market participant* provides notice of a non-performance event that would reduce the *demand response capacity* of the *hourly demand response* resource to 0 MW,
- The IESO did not send either advisory, standby, or activation notifications in advance of the test activation as per the timelines specified above, or
- The *IESO* cancels the test prior to the start of the first *dispatch hour* of the test activation. The *IESO* will appropriately inform *capacity market participants* with *HDR* resources about the test cancellation.

The *IESO* may determine that a test activation for an *HDR* resource is not required if the *IESO* is able to verify that the *HDR* resource delivered an amount equal to its *demand response energy bid* during the activation and satisfied the performance criteria defined below, during a previous activation within the same *obligation period.*

The *IESO* may schedule test activation for HDR resources regardless of whether the above conditions are met, if there is evidence that the resource is not able to deliver its *demand response capacity* at any time during the *obligation period*.

A second test within an *obligation period* will not be required if the *hourly demand response* resource delivers its allocated *capacity obligation* through a non-test-based or test-based activation during that *obligation period*.

Failure of a *demand response resource* to perform successful test activation may result in one or more of the following:

- Non-performance charges as specified in Market Manual 5.5: Physical Markets Settlement Statements,
- A subsequent test activation to be scheduled by the *IESO*,
- Revocation of reduced test duration, where applicable, and/or
- A compliance investigation to be performed by the *IESO*.

Performance Parameters:

Performance of an *HDR* resource means the *capacity obligation* allocated to the *HDR* resource is delivered for each hour of the activation period within a 15% dead-band (e.g. at least 85% of the *capacity obligation* must be delivered).

Performance will be assessed using the following parameters:

- The load reduction, up to a maximum of 115% of an *HDR* resource's energy bid quantity, will be considered per 5-minute interval
- The load reduction across each 5-minute interval will be summed for each activation hour (all 12 intervals) to determine the hourly load reduction

Reduction of Test Length of *HDR* Resources

An *HDR* resource that has delivered the *capacity obligation* allocated to the *HDR* resource during a four-hour activation (non-test-based[15] or test-based) will be subsequently tested for a one-hour duration. Tests following unsuccessful four-hour activations shall continue as four-hour activations.

The *IESO* may revert the test duration for an *HDR* resource from one hour back to four hours upon provision of advance notice, identifying which conditions were not satisfied.

An *HDR* resource's one-hour test duration will be maintained provided:

a) The *HDR* resource has demonstrated delivery of bid quantity in all activations (non-test-based or test-based) since qualifying for reduced testing, where the bid quantity must be equal to its *capacity obligation* allocated to the *HDR* resource in at least one of two most recent activations (non-test-based or test-based)
   - Delivery of bid quantity means the load reduction for each hour of the activation period, within a 15% dead-band compared to its demand response bid quantity[16] (e.g. at least 85% of the bid quantity must be delivered), and
   - Has performed within the Performance Parameters stated above

b) The *HDR* resource has not increased its *capacity obligation* by more than 5 MW from the last successful four-hour activation (non-test-based or test-based).

[15] Non-test-based activation can refer to an in-market or emergency activation

[16] Bid quantity means a statement of the quantity in the day-ahead commitment process and the *real-time energy market*, greater than 1 MW, entered by a *demand response market participant* for an *hourly demand response* resource to fulfill a *demand response capacity obligation* availability requirement.

IV. Non-Performance Event Management for Hourly Demand Response Resources

HDR Resources with a Capacity Obligation Acquired through the Demand Response Auction

Capacity market participants with *HDR* resources associated with *capacity obligations* acquired through a *demand response auction* are required to notify the *IESO* of reductions to *demand response capacity* of 5 MW or greater through submission of a notice of a non-performance event. Submissions must be per resource and must indicate the period over which *demand response capacity* is reduced.

Notice of a planned non-performance event must be submitted to ontca.dayahead@ieso.ca by 10:00 EST on the *business day* prior to the start of the non-performance event. Non-performance events occurring after 10:00 EST on the *business day* prior to the start of the non-performance event will be considered forced, and must be submitted to ontca.dayahead@ieso.ca at the time of the event.

For any quantity, *capacity market participants* whose *HDR* resources received an activation report with an activation notice on the *dispatch day* are required to notify the *IESO* Control Room by telephone as soon as practical for any reduction to *demand response capacity.*

Capacity market participants are required to update *bids* for *HDR* resources for any reduction to *demand response capacity* occurring on the *pre-dispatch day* or *dispatch day* to reflect the reduced *demand response capacity.*

HDR Resources with a Capacity Obligation Acquired through the Transitional Capacity Auction

Capacity market participants with *HDR* resources associated with a *capacity obligation* acquired through a *transitional capacity auction* are required to maintain records of all reductions to *demand response capacity* of 5 MW or greater during an *obligation period*. The IESO may request the records for a period of 1 year from the end of the associated *commitment period.* If requested, these records must be provided to the IESO by email by the deadline defined by the IESO. The records must contain the following details:

- Description of Event
- Resource name
- Trade Date
- Hours of reduced capacity
- Registered capacity of the *HDR* resource
- Amount of reduction (MW) to *demand response capacity*
- Action taken to manage energy bid

For any quantity, *capacity market participants* whose *HDR* resources received an activation report with an activation notice on the *dispatch day* are required to notify the *IESO* Control Room by telephone as soon as practical for any reduction to *demand response capacity.*

Capacity market participants are required to update *bids* for *HDR* resources for any reduction to *demand response capacity* occurring on the *pre-dispatch day* or *dispatch day* to reflect the reduced *demand response capacity.*

4.3 All Market Participants

As per *market rules* and the *operating agreements* between transmitters and the *IESO*, *IESO*'s *outage* assessments will not include assessments of impacts to the *reliability* of individual customer connections. Assessing the *reliability* of individual customer connections is the role of the transmitter who is required to:

- Coordinate *outages* impacting customer connections, and
- Recommend changes to transmission configuration and or recall or cancel outages to secure the supply to customer connections during a *high risk operating state*.

4.3.1 Monitoring and Control Equipment

Market participants are required to report planned and *forced outages* to monitoring and control equipment, data concentrating facilities that aggregate monitoring and control information from more than one *facility*.

For *forced outages, market participants* are required to respond and restore these facilities to a fully operational state within the time frames specified by Chapter 4, Section 7.7 of the *market rules*. Based on the impact of the equipment's unavailability on the *reliability* and/or operability of the *IESO*-controlled grid, the *IESO* may notify *market participants* to respond within a longer or shorter period that those specified in Sections 7.7.2 and 7.7.3 of the *market rules*, provided that, where the time to respond and restore is less than 24 hours, the *market participant* will use commercially reasonable efforts to achieve such direction (*MR* Ch. 4, Sec. 7.7.4).

Table 4-9 provides example codes for *market participants* when submitting *planned outage* requests to monitoring and control equipment:

Table 4-9: Example Codes for Planned Outages to Monitoring and Control Equipment

Priority Code	Constraint Code	Purpose Code
Planned	OOS	Other

4.3.2 System Tests

Power system tests typically involve abnormal configurations of the power system, extensive coordination during work, or unusual precautions to ensure the *reliability* and/or operability of the *IESO*-controlled grid. Tests covered by these requirements include, but are not limited to (*MR* Ch. 5, Sec. 6.6):

- The deliberate application of short circuits,
- *Generation unit* and *transmission system* stability tests,
- Planned actions which cause abnormal voltage, frequency or overloads,
- Planned abnormal station or system setups with inherent risk, and
- Tests of equipment for which there is some real or potential risk of widespread impact on the *IESO*-controlled grid.

In order to gain approval for the test, *market participants* arranging the test must submit the following details (*MR* Ch. 5, Sec. 6.6.2):

- Equipment involved,

- The relevant details of contracts or agreements as they relate to the test activities,
- Preferred and alternative dates and times for the conduct of the test activities,
- Unusual system conditions or setup required,
- Any required changes in setup, power flow, voltage, frequency, etc., that could have an impact on the *reliability* and/or operability of the *IESO*-controlled grid,
- Details of special readings, observations, etc., to be recorded by operating personnel, and
- Identity of personnel who are directly involved in the test, their location and the means of communicating with them.

The *IESO* will approve the *outage* request if it is determined that the test will not have an adverse effect on the *reliability* and/or operability of the *IESO-controlled grid* or on the operation of the *IESO*-administered markets.

Where required, arrangements shall be made for a Test Coordinator to be appointed. The name and role of the Test Coordinator shall be specified in the *outage* submission. The duties of the Test Coordinator include:

- Defer, limit, or stop the System Test due to unfavorable system conditions or test results,
- Monitor test conditions in the area involved, and
- Act as a communicator, and other roles as agreed upon in the *outage* submission.

If the *outage* submission involves additional *outage*s or safety code procedures, the requestor shall ensure that *outage* requests are submitted by the appropriate *market participant*(s).

Examples of requirements that will not be considered power system tests and should be arranged in the normal manner for *outage*s include:

- Routine *generation unit* rejections,
- Routine protection and control maintenance and testing,
- Routine commissioning tests, and
- Work or testing on hydraulic waterways and storage.

Market participants are required to use the Testing Purpose Code when submitting *outage* requests, Table 4-10 provides an example:

Table 4-10: Example Codes When Submitting Planned System Test Requests

Priority Code	Constraint Code	Purpose Code
Planned	IS	Testing

4.3.3 Testing of Ancillary Services

The *IESO* shall test facilities that intend to, or do, provide *ancillary services* to the *IESO-controlled grid*.

Note: During such testing, the *IESO* may submit *outage* requests on behalf of *market participants*. These will only be visible to the *IESO* and used for informational purposes.

Tests must be successfully completed prior to entering into a *contracted ancillary services* contract, for a *facility* providing *regulation* or black start services, and at least annually thereafter throughout the contract period. Tests shall be arranged and scheduled at a time mutually agreeable to both the *ancillary service provider* and the *IESO* in accordance with the *outage* scheduling processes outlined in this *market manual*.

For contracted providers of the Reactive Support and Voltage Control Service the *IESO* may require tests in accordance with *MR* Ch. 5, Sec. 4.9.

Performance standards and testing procedures are prescribed in the "*IESO* – Ancillary Service Provider (ASP) Agreements for Procurement of Certified Black Start Facilities". Schedule 2 of this Agreement stipulates the required black start performance standards, with Schedule 3 articulating the required testing procedures.

The performance standards for contracted reactive support and voltage control are stipulated in *MR* Ch. 4, App 4.2.

4.3.4 Testing Operating Reserve Providers

The *IESO* may conduct unannounced tests of any *market participant*'s *facility* registered to provide *operating reserve* and currently scheduled to provide *operating reserve*.

Note: During such testing, the *IESO* may submit *outage* requests on behalf of *market participants*. These will only be visible to the *IESO* and used for informational purposes.

The *IESO* will assess *market participants*' compliance with the *operating reserve dispatch instruction* according to the respective *operating reserve offer* submission data. For the purposes of this manual, a failure to meet an *operating* reserve target during an *operating reserve* activation (ORA) will also be deemed as a test failure.

If *dispatchable load* facilities providing *operating reserve* identify special testing requirements, the *IESO* will coordinate testing within the first week of the *market participant*'s acceptance in the market as an *operating reserve* provider, or as soon as possible. Subsequent testing will occur on a periodic basis.

Tests shall be arranged in accordance with *MR* Ch. 5, Sec. 4.9 and 4.10.

Reserve testing is the responsibility of the *IESO* and is conducted by the control room operators (CROs). The CROs will implement unannounced tests taking into account any *facilities* with poor past performance that require additional testing.

If reserve testing is implemented on a resource that is part of an aggregate, compliance will be assessed on the output of the aggregate.

Note: If there is non-compliance to actual reserve activations, the following approach will be used with respect to removing offers.

Table 4-11: Implementing and Assessing Reserve Tests

If a market participant…	The IESO will…
Fails an **initial reserve test** or an ORA, (i.e., fails to meet dispatch target within prescribed time [10 or 30 minutes])	1. (At IESO discretion)[17] direct the *market participant* to remove its reserve *offers* on the resource for the **remainder of that day and the next day**. 2. Allow these changes within the two-hour mandatory window. 3. Retest the unit, normally within a week after it submits reserve *offers* again.
Fails their **first retest** of the reserve test or an ORA, (i.e., fails to meet dispatch target within prescribed time [10 or 30 minutes])	1. Direct the *market participant* to remove its reserve *offers* on the resource for **one week**. 2. Allow these changes within the two-hour mandatory window. 3. Retest the unit, normally within a week after it submits reserve *offers* again.
Fails their **second retest** of the reserve test or an ORA, (i.e., fails to meet dispatch target within prescribed time [10 or 30 minutes])	1. Direct the *market participant* to remove its reserve *offers* on the resource **indefinitely**. 2. Allow these changes within the two-hour mandatory window. 3. Initiate follow-up with the involved *market participant.* As a result of this follow-up, a decision will be made as to whether the *facility* should be removed from the reserve market, and the circumstances for allowing the return to the reserve market.
• Fails a reserve test because of an **unforeseen** *forced outage* or equipment limitation, and • **Is NOT** a *dispatchable load*	Request the *market participant* to submit an outage to derate or force the equipment out-of-service.

[17] Discretion may be applied in determining whether or not to direct a *market participant* to remove its reserve offers after a failed activation. The following may be taken into consideration:

- System conditions may exist where available *operating reserve* is particularly limited (e.g., freshet, tight supply conditions). Removal of reserve offers may lead to potential shortfall.
- A resource that failed to meet the reserve target within the required time may have faced legitimate circumstances that led to the failed activation. If these circumstances have been, or are expected to be rectified, then future activation of reserve is expected to be met without failure.

If a market participant…	The IESO will…
• Fails a reserve test because of an **unforeseen** *forced outage* or equipment limitation, and • **Is** a *dispatchable load*	1. Request the market participant to change its energy *bid* to reflect the derate or force the equipment out-of-service. 2. Request the *dispatchable load* to remove its reserve *offers*, as the DSO cannot handle derates on *dispatchable loads*. 3. (Once the *forced outage* condition has been repaired) allow the *market participant* to resubmit its reserve *offers* within the two-hour mandatory window.

4.3.5 Hold-offs

Hold-offs are restrictions in the use of transmission lines to facilitate maintenance activities. Automatic reclosure is blocked and manual reclosure is restricted until contact is made with the hold-off party. Single and multiple element hold-offs may be granted Auto AA or FAA.

Market participants are required to use the HOLDOFF Constraint Code when submitting *outage* requests, Table 4-12 provides an example:

Table 4-12: Example Codes When Submitting Planned Hold-off Requests

Priority Code	Constraint Code	Purpose Code
Planned	HOLDOFF	Other

4.3.6 New and Replacement Facilities

Market participants are required to report an *outage* prior to (*MR* Ch. 5, Sec. 6.4A):

- Energization of any new *facility*, or
- Energization of any new *facility* equipment impactive on the *reliability* and/or operability of the *IESO*-controlled grid, or
- Returning into service replacements of any existing *facility* equipment impactive on the *reliability* and/or operability of the *IESO*-controlled grid.

Outage submissions that request the energization of new facilities are not eligible to be requested for the 1-Day *Advance Approval* process as the impact of introducing a new *facility* cannot be adequately assessed by the *IESO* within the timelines of the 1-Day *Advance Approval* process. In addition, *market participants* must ensure that all applicable *facility* registration requirements are complete, prior to the commencement of any such *outage*.

Table 4-13 provides example codes for *market participants* when submitting *planned outage* requests to new and replacement facilities:

Table 4-13: Example Codes When Requesting Planned Outages to New and Replacement Facilities

Priority Code	Constraint Code	Purpose Code
Planned	MUSTRUN	Replacement

– End of Section –

5. Replacement Energy to Support Planned Outages

A *generation facility* may notify the *IESO* that it will arrange replacement *energy offers* in the form of an import to support a *planned outage* request or when requesting an extension to an *outage*. Such a notification does not obligate the *generation facility* to notify the *IESO*, and if so notified, the *IESO* to approve or accept any such arrangement. The *generation facility* may withdraw the arrangement for replacement *energy offers* at any time up to final approval of the *outage* or up to the final approval of the extension (*MR* Ch. 5, Sec. 6.3.6).

Where, based on the *IESO*'s assessment of *security* and *adequacy*, the *IESO* permits the *generation facility* to arrange for replacement *energy*, the *IESO* shall determine the minimum MW amount to be arranged as replacement *energy* (*MR* Ch. 5, Sec. 6.3.9) based on the following:

- The MW amount of replacement *energy* shall be no less than the forecast shortfall from the *Adequacy* Report as determined prior to *advance approval* being provided or based on more current information in the *Adequacy* Report,
- Where the shortfall occurs beyond the period of 14 days, the *IESO* will identify the weeks of shortfall and the maximum amount to be arranged for these weeks based on the day 15 to 34 *Adequacy* Reports or the Reliability Outlook report prior to *advance approval* being provided. The *generation facility* should wait until the shortfall is detailed in an *Adequacy* Report covering the day 0 to 14 period, to identify the specific shortfall hours and amounts to finalize the amount of replacement *energy*. In any case, replacement *energy* must be finalized by the *generation facility* no later than 16:00 EST three *business days* prior to the commencement of the shortfall week(s), and
- Shall not exceed the amount of *energy* that was agreed to at the time of finalization or 500 MW.

Generation facilities shall convey to the *IESO* their arrangement for replacement *energy* by way of the comments field in the *outage* management system with the following information:

- The *intertie* where *offers* will be submitted,
- A unique identifier associated with the e-Tag or a unique e-Tag ID,
- The MW amount to be offered and the duration of the *offers* (if finalized), and the *registered market participant* associated with a *registered facility* that is a *boundary entity* that shall submit the offers.

Once the *IESO* has approved or provided additional direction to the *generation facility* specifying the details of the replacement *energy* import offers, the *generation facility* whose *outage* was approved is obligated to ensure that these *offers* are submitted to the *IESO* for pre-*dispatch* scheduling. The *boundary entity* who shall provide replacement *energy* and that is subject to *dispatch instructions* received from the *IESO*, is subject to the failed *intertie* transaction rules in *MR* Ch. 7, Sec. 7.5.8A and 7.5.8B and *MR* Ch. 3, Sec. 6.6.10A to 6.6.10C and the related compliance guidelines.

The *IESO* may specify the *intertie*(s) where the replacement *energy* is to be scheduled in order to meet *reliability* requirements.

The *IESO* shall have the right to specify the duration of *offers* necessary to support the *outage* request (*MR* Ch. 5, Sec. 6.3.9). The *IESO* shall make this determination based on the following:

- *Reliability* and/or operability impacts on the *IESO*-controlled grid,
- Forecast capabilities of the *interconnections* for the duration of the *planned outage*, and
- Forecast *adequacy* of neighbouring jurisdictions for the duration of the *planned outage*.

The duration that replacement *energy offers* to be submitted to the *IESO* as part of the pre-*dispatch* scheduling process shall be:

- No less than the period of the shortfall hours applied to each day of the week(s)[18] of the shortfall, and
- No greater than the total duration of the *outage*.

For example,

A *generation facility* requests for a 300 MW *outage* over 3 weeks. A shortfall of 100 MW is identified on the Tuesday of the second week between 9 AM to 10 AM. The *IESO* will notify the *market participant* of the shortfall and reject the *outage*.

In order to get approval for the *outage* request, the *market participant* must agree to arrange for replacement *energy* from 9 AM to 10 AM (shortfall hours) for all days of the second week.

However, the *market participant* may wait until 16:00 EST 3 *business days* prior to the commencement of the second week of the *outage*, to finalize the amount and hours of replacement *energy*. By waiting to finalize the amount, the *generation facility* accepts that the purchase amount may increase from the amount forecast when the *outage* was given *advance approval*.

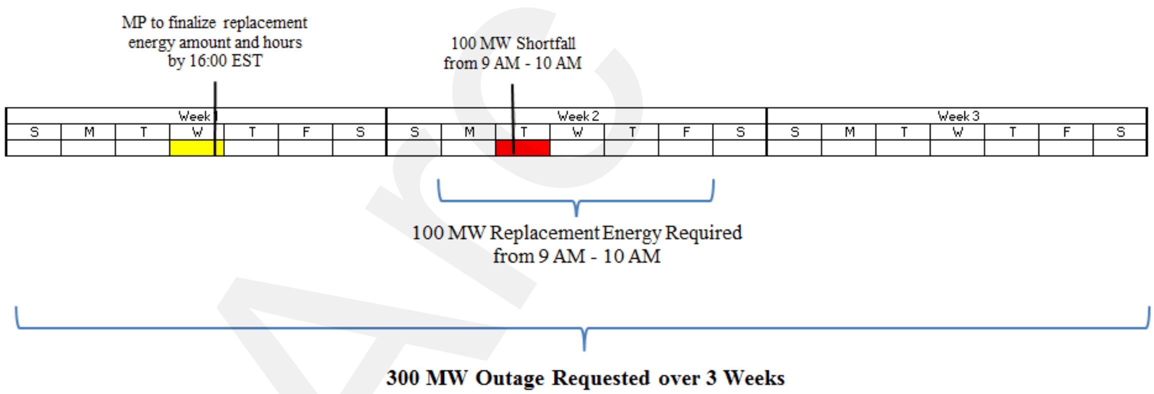
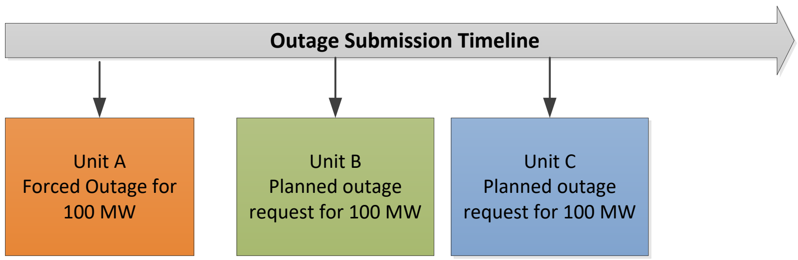


Figure 5-1: Purchase of Replacement Energy – Requirements and Confirmation Timeline

[18] For the purposes of *outage* replacement *energy*, week is defined as weekdays (Monday to Friday excluding holidays). Where shortfalls occur on a weekend or holiday, the *IESO* will identify this requirement to the *generation facility* and the *generation facility* will be required to arrange for replacement *energy* to cover these shortfalls.

For example,

<table>
<tr><th>If…</th><th>Then…</th></tr>
<tr><td>The following outages create a shortfall of 300 MW:

</td><td>Unit B and Unit C are offered the opportunity to purchase replacement energy.</td></tr>
<tr><td>Unit B chooses to purchase replacement energy</td><td>Unit B is required to purchase 200 MW, to clear shortfall caused by forced outage plus its outage.
Unit C is required to purchase 100 MW</td></tr>
<tr><td>Unit B does not choose to purchase replacement energy</td><td>Outage to Unit B is rejected.
Shortfall is reduced to 200 MW
Unit C is required to purchase 200 MW, to clear shortfall caused by forced outage plus its outage.</td></tr>
</table>

Generation facilities that have arranged replacement *energy* to support their *planned outage* are assessed based on priority according to the following:

- When requesting *outage* approvals during periods of *adequacy* concerns, *generation facilities* who have arranged for replacement *energy* to support a *planned outage* will have a higher priority than *outage*s that have chosen not to arrange replacement *energy* (and would otherwise be rejected).
- Where more than one *generation facility* has indicated that they wish to arrange for replacement *energy* and, because of *security* or *adequacy* concerns, *advance approval* cannot be given to both the *generation facilities*, the *generation facility* with an earlier priority date will be given priority.

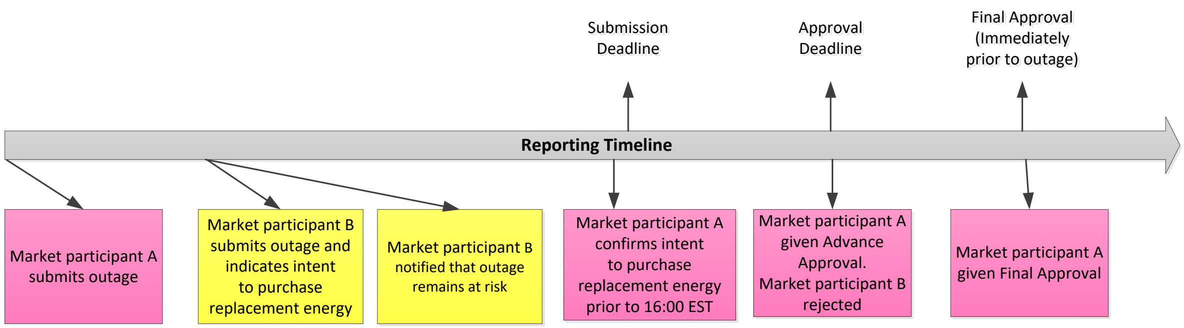


Figure 5-2: Precedence of Outages Based on Purchase of Replacement Energy

- Where a *generation facility* is identified to be at risk after the replacement *energy* confirmation timeline but before the *advance approval* timeline as detailed in Section 2.7, and then confirms the intent to arrange replacement *energy* before the *advance approval* timeline, the *generation facility* shall maintain its priority date relative to *outage*s that confirmed replacement *energy* before the confirmation timeline.
- Where a *generation facility* has to be revoked or recalled due to *energy* shortfalls identified after the *advance approval* or final approval was granted, precedence will be given based on the priority date, regardless of whether the approval is based on arranging replacement *energy*.
- Where a *generation facility* indicates that they intend to arrange for replacement *energy* and they do not have priority date precedence over other *generation facilities* who may elect to arrange for replacement *energy* they will be notified that they may not be eligible. A final decision regarding eligibility cannot be made until the *outage* submission deadline. In this situation, it would be prudent for *market participants* without priority date precedence to wait until the submission deadline before arranging replacement *energy*.

– End of Section –

6. Disputes and Compliance

6.1 Disputes

The *IESO* or an Applicant may initiate the Dispute Resolution process in accordance with *MR* Ch. 3, Sec. 2 if either believes the circumstances warrant such action. Specifically, *market participants* may dispute any decision of the *IESO* related to *outage* management, such as rejection of an *outage* submission, revocation or recall of an approved *outage*, or denial of *outage* compensation. However, *market participants* must continue to follow the direction of the *IESO* until such time as the Dispute Resolution panel renders a decision. For more information regarding the dispute resolution process, refer to Market Manual 2.1: Dispute Resolution.

6.2 Market Surveillance and Compliance

A Market Surveillance Panel was established pursuant to the "*Electricity Act*, 1998" for the purpose of identifying inappropriate market conduct, market design flaws and to make sure that the *IESO-administered market* is fair and efficient. *IESO* staff may forward potential non-compliant actions of *market participants* to the *IESO* Market Assessment and Compliance division. Refer to Market Manual 2.6: Treatment of Compliance Issues and Market Manual 2.7: Treatment of Market Surveillance Issues for more information regarding the dispute resolution process.

– End of Section –

Appendix A: Forms

The following form is used in connection with the *outage* management process. This form is available to *market participants* on the *IESO* website:

Form Name	Form Number
Request for Outage Compensation	IMO_FORM_1350

– End of Section –

Appendix B: Outage Reporting Requirements

Outages must be coordinated with the *IESO* (and reported to the *IESO*) when any of the conditions in the following table are met:

Table B-1: Outage Reporting Requirements

Facility Group	Elements of the Facility Group for which Outages must be Reported
Transmission facilities[19] operated at voltages ≥ 100 kV	All
Transmission facilities operated at voltages < 100 kV	Removal of step-down transformers with a low-side voltage < 100 kV
	Involve the unloading of step-down transformers or their individual windings[20]
	Require paralleling or separation of buses via operation of bus tie breaker
	Result in a load transfer ≥ 20 MW between step-down transformer stations
	Adversely affect a *generation facility* or *dispatchable load*
Transmission or Distribution Reactive resources	15 MVAR or greater in areas electrically south of Essa TS in Barrie
	10 MVAR or greater in areas electrically north of Essa TS in Barrie
	Synchronous Condensers and Static VAR Compensators (SVCs)
Power system auxiliaries[21]	Control systems designed to dynamically respond to system conditions such as: • Power system stabilizers (PSSs) • *Automatic voltage regulation* (*AVR*)
	Operating aids such as: • Circuit auto-reclosure schemes • Voltage reduction facilities
	• Under-frequency load shedding (ULFS) facilities

[19] Facilities that form part of or are connected to the *IESO-controlled grid* and used for the purpose of transmitting or distributing electricity. These facilities may be owned by a transmitter, *wholesale customer*, distributor or *generator*.

[20] Where multiple facilities involve logic that require those facilities be operated together (i.e., both a switch and a breaker are arranged in series and the switch cannot be operated without first opening the breaker), it is only necessary to report on one of those facilities.

[21] The following power system auxiliaries are excluded from *outage* reporting:

- Switchyard auxiliaries that do not affect, or the loss of an additional element that does not affect, the operation of the *IESO*-controlled grid or the operation or capability of components of the *IESO*-controlled grid.
- Step-down transformer station low voltage bus protections and low voltage reactive resource protections (capacitors), unless they cause unavailability of the component and/or a reconfiguration of the *IESO*-controlled grid.
- Feeder protections and feeder breaker auto-reclosures, unless they create a load transfer during system tests, or restrict access to the *IESO*-administered markets of embedded facilities.

Facility Group	Elements of the Facility Group for which Outages must be Reported
	Primary or backup protection systems designed to detect and isolate failed or faulted elements
	Breaker Failure Protection
	Breaker Trip Coil Test
	Special Protection Systems (SPS) that detect identified system conditions and take corrective action such as: • Combined *generation facility* and load rejection schemes • Reactor tripping schemes
	Communication facilities such as: • SCADA • RTUs, ICCP links or telemetry facilities for display of quantities • *Market participant dispatch* tools and facilities
	Communication facilities such as Voice, data and protection tone communications
	Switchyard auxiliaries such as: • AC and DC *station services* • Supervisory control facilities or Control Room bench-boards • Multi-breaker air supply systems including compressor plants and cable cooling systems
Non-*registered facilities* or embedded facilities[22]	Result in a change of more than 20 MW in *demand* or supply in an hour from what is typical for that hour (i.e. large industrial customers that periodically shut down plants for maintenance or holidays)
Dispatchable load facilities/ Wholesale customers	Result in changes of more than 20 MW in *demand* or supply in an hour from what is typical for that hour.
Distributors and *Transmitters*	Result in changes of more than 20 MW in *demand* or supply in an hour from what is typical for that hour.
	Demand control actions, including *demand* management, voltage reductions and disconnections.
Generation Facilities	All *generation facilities*
	Segregated Mode of Operation (SMO)
	Available but not operating
	Deratings: • Derating equal to the greater 2% of rated output or 10 MW • Holds at a specific load for >30 minutes during start-up
	Affects the maximum output or minimum load of a *generation unit*
	A component failure, operational limit or other circumstance that will cause the unit to trip

[22] If the facility is not registered with the *IESO*, this responsibility falls on the *market participants* (i.e. *transmission customers* for the facility).

Facility Group	Elements of the Facility Group for which Outages must be Reported
	Plant auxiliaries that affect more than a single *generation facility* or aggregate of *generation facilities* where the loss of an additional element results in multiple unit/aggregate shutdowns within 48 hours such as: • Service air or instrument air • Boiler feed pumps • Station Service
	Affects the availability to provide *ancillary services* such as: • *Automatic Generation Control (AGC)* • Voltage support • Black start service
Testing	All tests described in Section 4.3.2: System Tests
	Testing of *generation units*, including: • In-service or commissioning tests • Testing of derated units at levels above the derated levels • Testing of units currently on *outage* • Tests of facilities providing *ancillary services*
All Equipment	Hold-off
	Energization: • Energization of any new *facility*, or • Energization of any new *facility* equipment impactive on the *reliability* and/or operability of the *IESO*-controlled grid, or • Returning into service replacements of any existing *facility* equipment impactive on the *reliability* and/or operability of the *IESO*-controlled grid.

– End of Section –

Appendix C: Equipment Classes and Applicable Constraint Codes

Table C-1: Applicable Constraint Code per Equipment Class

Equipment Class	Constraint Code										
	OOS	IS	DRATE	MUSTRUN	HOLDOFF	*AVR*/PSS OOS	ASP OOS	PROT OOS	BF PROT OOS	BTCT	INFO	ABNO
Line	x	x			x			x			x	
Line Section	x	x			x			x			x	
Breaker	x	x							x	x	x	
Disconnect Switch	x	x									x	
Bus	x	x						x			x	
Transformer	x	x						x			x	
Reactor	x	x	x					x			x	
Capacitor	x	x	x					x			x	
SVC	x	x	x	x				x			x	
Converter	x	x	x	x				x			x	
Filter	x	x	x					x			x	
Phase Shifter	x	x						x			x	
Voltage Regulator	x	x						x			x	
UFLS Relay	x	x									x	

Equipment Class	Constraint Code											
	OOS	**IS**	**DRATE**	**MUSTRUN**	**HOLDOFF**	***AVR*/PSS OOS**	**ASP OOS**	**PROT OOS**	**BF PROT OOS**	**BTCT**	**INFO**	**ABNO**
Synchronous Condenser	x	x	x	x				x			x	
Generation facility	x	x	x	x		x	x	x			x	x
Load	x	x	x	x			x	x			x	
AC/DC Station Service[23]	x	x									x	
SPS[23]	x	x									x	
Tone Communication Channels[23]	x	x									x	
RTU/ICCP/HUB Equipment[23]	x	x									x	
Other Communication Equipment[23]	x	x									x	
Other Miscellaneous Equipment[23]	x	x									x	

– End of Section –

[23] *Market participants* are required to input a description of the equipment for this equipment class, in the *outage* management system.

Appendix D: Criteria for 1-Day Advance Approval, Auto AA and FAA

Planned outage requests containing only low-impact equipment must be submitted for 1-Day *Advance Approval*. *Outage* requests containing eligible equipment, with no conflicting outage requests (See Section 3.2 for outage conflicts) and that satisfy low-impact criteria may be eligible to receive Auto *Advance Approval* (Auto AA) (i.e. automatically transition to Advance Approved status on submission) and in some cases may also receive Final Approval in Advance (FAA). The eligibility criteria for 1-Day *advance approval*, Auto AA and FAA are described in the table below.

Table D-1: Criteria for 1-Day Advance Approval, Auto AA and FAA

A Outage Type	B Equipment Class	C Constraint Code	D Low-impact Attributes	E Additional Conditions	F 1-Day *Advance Approval*	H Auto AA	I FAA
Generator outage	*Generation facility*	OOS, IS, DRATE, MUST RUN		Planned Start and End Date/Time are in the same day or Max Recall ≤ 15 min	Y	N	N
Available But Not Operating	*Generation facility*	ABNO		Priority Code = Information	N	Y	N
Automatic Voltage Regulation (*AVR*) or Power System Stabilizer (PSS)	*Generation facility*	*AVR*/PSS OOS	Only a Loss of Redundancy?" = YES (Answer)		Y	Y	Y
Ancillary Services	*Generation facility,* Load	ASP OOS		Planned Start and End Date/Time are in the same day or Max Recall ≤ 15 min	Y	N	N
Primary protections	Line, Line Section, *Generation facility,* Bus, Transformer, Reactor, Capacitor, SVC, Phase Shifter, Voltage	PROT OOS	"Only a Loss of Redundancy?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	Y	Y

A Outage Type	B Equipment Class	C Constraint Code	D Low-impact Attributes	E Additional Conditions	F 1-Day *Advance Approval*	H Auto AA	I FAA
	Regulator, Synchronous Condenser, Converter, Filter, Load		"Only a Loss of Redundancy?" = YES (Answer)	Max Recall is > 15 minutes	Y	N	Y
Holdoffs	Line, Line Section	HOLDOFF			Y	Y	Y
Breaker failure protections	Breaker	BF PROT OOS			Y	N	N
			"Adjacent breakers OOS?" = NO (Answer) AND "Only a Loss of Redundancy?" = YES (Answer) ELSE, IF Question: "Only a Loss of Redundancy?" = NO (Answer) THEN "CTs on both sides of the breaker?" = YES (Answer)	Only one piece of Equipment is on the Outage Request Continuous and ≤ 4 hours in duration No overlapping BF PROT OOS *outage*s at the same station	Y	Y	N
Breaker trip coil tests	Breaker	BTCT			Y	N	N
AC/DC station service	AC/DC Station Service	OOS	"Only a Loss of Redundancy?" = YES (Answer) "Does the SS supply Cooling to any equipment on the ICG?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	N	N
		OOS	"Only a Loss of Redundancy?" = YES (Answer) "Does the SS supply Cooling to any equipment on the ICG?" = NO (Answer)	Max Recall is ≤ 15 minutes	Y	Y	Y

A **Outage Type**	B **Equipment Class**	C **Constraint Code**	D **Low-impact Attributes**	E **Additional Conditions**	F **1-Day *Advance Approval***	H **Auto AA**	I **FAA**
		IS		Max Recall is ≤ 15 minutes	Y	N	N
Tone communication channels	Tone Communication Channels	OOS	Only a Loss of Redundancy?" = YES (Answer) "RTU or HUB Affected?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	N	N
		OOS	Only a Loss of Redundancy?" = YES (Answer) "RTU or HUB Affected?" = NO (Answer)	Max Recall is ≤ 15 minutes	Y	Y	Y
		IS		Max Recall is ≤ 15 minutes	Y	N	N
Radial lines	Transmission circuit	OOS, IS, DRATE		Facility Class = 3 (Low-impact)	Y	Y	N
Transmission facilities operated at voltages < 100 kV	Breaker, Bus, *Disconnect* Switch, Transformer, Load	OOS, IS, DRATE		Facility Class = 3 (Low-impact)	Y	Y	N
LV reactive devices	Capacitor, Reactor	OOS		Facility Class = 3 (Low-impact)	Y	N	N
UFLS equipment	UFLS Relay	OOS		Facility Class = 3 (Low-impact) UFLS Validation Threshold passes (i.e. Sum UFLS Area *Outages* < UFLS Area Outage Margin)	Y	Y	Y
Special Protection Scheme	SPS	OOS	Only a Loss of Redundancy?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	N	N

A **Outage Type**	**B** **Equipment Class**	**C** **Constraint Code**	**D** **Low-impact Attributes**	**E** **Additional Conditions**	**F** **1-Day *Advance Approval***	**H** **Auto AA**	**I** **FAA**
		IS		Max Recall is ≤ 15 minutes	Y	N	N
RTU/ICCP/HUB Equipment	RTU/ICCP/HUB Equipment	OOS	Only a Loss of Redundancy?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	N	N
		IS		Max Recall is ≤ 15 minutes	Y	N	N
Other Equipment	Other Communication Equipment, Other Miscellaneous Equipment	OOS	Only a Loss of Redundancy?" = YES (Answer)	Max Recall is ≤ 15 minutes	Y	N	Y
		IS		Max Recall is ≤ 15 minutes	Y	N	N

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References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_PRO_0016	Market Manual 1.2: Facility Registration, Maintenance and De-Registration
MDP_PRO_0017	Market Manual 2.1: Dispute Resolution
IMO_PRO_0019	Market Manual 2.2: Exemption Application and Assessment
MDP_PRO_0022	Market Manual 2.6: Treatment of Compliance Issues
MDP_PRO_0023	Market Manual 2.7: Treatment of Market Surveillance Issues
IMP_PRO_0024	Market Manual 2.11: Reliability Outlook and Related Information Requirements
MDP_PRO_0033	Market Manual 5.5: Physical Markets Settlement Statements
IMP_PRO_0033	Market Manual 7.2: Near-Term Assessments and Reports
IESO_MAN_0077	Market Manual 9.2: Submitting Operational and Market Data for the DACP
PRO-357	Market Manual 13.1: Capacity Export Requests
N/A	Electricity Act, 1998
IESO_TPL_0020	*IESO* – Ancillary Service Provider (ASP) Agreement for Procurement of Certified Black Start Facilities
GDE-259	Outage Coordination and Scheduling System (OCSS) CROW Web Client User Guide

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