

New Brunswick System Operator (NBSO)

Review of the NBSO Dispatch Algorithm

May 3, 2010



Contents

Section I: Background	1
Introduction	1
Overview of the Dispatch Algorithm	1
Purpose of the Review	2
Limitations of Review	2
Section II: Results	3
Independent Reviewer's Report	3
Exhibit A: Management Interpretations	4
Exhibit B: Additional Information provided by NBSO	6
Section III: Scope & Methodology	7
Scope of Review	7
PwC Methodology - Approach	9
Appendices	
A. MOD Optimization Outputs	
B. Draft Market Procedure 18	
C. New Brunswick Electricity Market Rules Chapter 6	

Section I: Background

Introduction

The New Brunswick System Operator (NBSO) is a not-for-profit independent corporation that was formed in October 2004 to support a competitive wholesale electricity market.

The NBSO ensures that the electricity market within the province of New Brunswick i) operates efficiently, ii) treats all market participants fairly, iii) provides all transmission customers with open access to use of the regional electric transmission system and iv) supports the reliability of the Integrated Electricity System.

One of NBSO's primary responsibilities is to maintain the reliability of the integrated electrical system in real-time. This responsibility takes the form of operation of the NBSO-controlled grid including the provision of load forecasting, outage coordination, generation scheduling, voltage management, and ancillary services provision.

As part of the NBSO's mandate to administer and operate a competitive market, NBSO has implemented a dispatch algorithm. The objective of the dispatch algorithm is system optimization in order to provide an economical dispatch of resources to meet consumer load while respecting system constraints.

Overview of the Dispatch Algorithm

NBSO's dispatch algorithm is modeled within the Market Optimization and Dispatch (MOD) application. The MOD application is used by the NBSO for the purposes of system optimization and its outputs form the basis of commitment schedules and dispatch instructions for energy and Ancillary Services.

NBSO utilizes the MOD application to perform constrained and unconstrained optimization. Constrained optimization is reflective of the actual physical constraints imposed by facility characteristics as well as the transmission system. Unconstrained optimization ignores the constraints imposed by the transmission system in order to determine a marginal cost that balances supply with demand without the impacts of the transmission system.

Using MOD, the NBSO executes a variety of system optimizations in various time frames for various purposes, including day-ahead optimization, hour-ahead optimization and unconstrained market settlement optimization. Each of these optimizations uses the same system model and optimization methodology but differ in time frame, specific inputs and constraints applied to the optimization.

Day-ahead optimization is undertaken on the previous business day and considers the full 24 hours of the dispatch day. This optimization is used as the basis for Preliminary Day Ahead Commitment Schedule (PDACS) and the Final Day Ahead Commitment Schedule (FDACS). FDACS provides market participants with a final commitment schedule for their generation facilities based on which generation facilities can prepare for their schedule generation and Ancillary Services supply requirements.

Hour-ahead optimization occurs throughout the dispatch day utilizing the latest information available regarding forecasted load, Balanced Schedules, transmission outages, generation facility capabilities and dynamic dispatch data. This produces a commitment schedule for the next dispatch hour, Final Hourly Commitment Schedule (FHCS) and a preliminary schedule for the next three hours. The FHCS is further utilized in the creation of Dispatch Instructions for generation facilities.

Purpose of the Review

NBSO's operation of the electricity market including the economic scheduling and dispatch of resources is governed by the Market Rules for the New Brunswick Electricity Market (Market Rules).

Market Rule 6.1.4 state that the NBSO shall ensure that its internal procedures and systems relating to scheduling and dispatch objectives are subject to an independent design and performance review. The NBSO has engaged PricewaterhouseCoopers LLP (PwC) to review the operation and application of the dispatch algorithm in the MOD application to assess if it is in compliance with Sections 6.1 – 6.10, 6.13, 6.16 and 6.18 from Chapter 6 of Market Rules.

Chapter 6 of the Market Rules state that NBSO shall, in scheduling energy transactions and Ancillary Services, pursue the following objectives while respecting facility capabilities, Balanced Schedules, any daily energy limits and transmission constraints:

- maintaining reliability of the Integrated Electricity System;
- completion of energy transactions scheduled by Market Participants under Bilateral Contracts;
- minimizing energy transactions other than those scheduled under Bilateral Contracts or as Ancillary Services; and
- the economical dispatch of resources available to meet hourly demand

Additionally, NBSO management has provided PwC with management interpretations that further supplement the Market Rules' scheduling and dispatch objectives noted above. These management interpretations are set out in **Exhibit A** of Section II.

PwC performed this review on the operation and application of the dispatch algorithm for the test day of October 6, 2009. The report addresses NBSO's compliance with the Sections 6.1 – 6.10, 6.13, 6.16 and 6.18, inclusive of the interpretations made by NBSO management.

Limitations of Review

A review is substantially less in scope than an audit in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion of whether the NBSO's dispatch algorithm is in compliance with the Market Rules. A review does not contemplate obtaining an understanding of internal control over the operation of the dispatch algorithm or assessing control risk, tests of records provided and responses to inquiries by obtaining corroborating evidential matter, and certain other procedures ordinarily performed during an audit. Thus, a review does not provide assurance that we will become aware of significant matters that would normally be disclosed in an audit.

Section II: Results

Independent Reviewer's Report

May 3, 2010

To the NBSO Board of Directors and Market Participants:

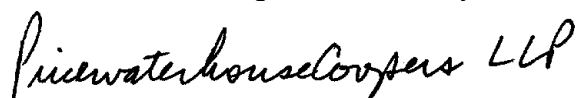
We have reviewed the New Brunswick System Operator (NBSO)'s operation and application of the dispatch algorithm in the Market Optimization and Dispatch (MOD) tool to assess its compliance, for the test day of October 6, 2009, with Sections 6.1 – 6.10, 6.13, 6.16 and 6.18 from Chapter 6 of the Market Rules, inclusive of the interpretations made by the NBSO as set out in **Exhibit A** of this report. Our review was made in accordance with generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures and discussion related to information supplied to us by the NBSO.

A review does not constitute an audit and consequently we do not express an audit opinion on this matter.

Based on our review, nothing has come to our attention that causes us to believe that the operation and application of the dispatch algorithm in the Market Optimization and Dispatch (MOD) tool is not operating, in all material respects, in accordance with Sections 6.1 – 6.10, 6.13, 6.16 and 6.18 from Chapter 6 of the Market Rules, inclusive of the interpretations made by the NBSO as set out in **Exhibit A** of this report except that in our review, we noted that where the output of a facility is constrained by a transmission constraint and a re-dispatch of energy is required for that facility in order to meet Regulation Ancillary Service requirements, the combination of energy and Ancillary Services dispatched for the facility by the MOD tool did not respect the relevant transmission constraint.

Subsequent to October 6, 2009, the NBSO identified and updated the MOD application to remediate the above noted exception; see **Exhibit B** for additional information provided by NBSO management relating to this exception. We reviewed the dispatch algorithm in the updated version of the MOD tool as of May 5, 2010 for compliance with the transmission constraint where the output of a facility is constrained by a transmission constraint and a re-dispatch of energy is required for that facility in order to meet Regulation Ancillary Service requirements. Our subsequent testing did not review or consider any other aspect of the MOD tool.

Based on our review as of May 5, 2010, nothing has come to our attention that causes us to believe that the dispatch algorithm in the updated version of the MOD application is not, in all material respects, in compliance with transmission constraint where the output of a facility is constrained by a transmission constraint and a re-dispatch of energy is required for that facility in order to meet Regulation Ancillary Service requirements.



PricewaterhouseCoopers LLP
Calgary, AB

Exhibit A: Management Interpretations

In circumstances where additional clarifications of the Market Rules were required, the NBSO made certain management interpretations of the referenced sections of the Market Rules. These management interpretations are set out below.

Daily Energy Limits on Generation Facilities

Market Rule 6.1.2 states that the objective function should have regard for any Daily Energy Limits available in dispatch data. The objective function does not consider these limits since the participants are not currently required to supply these daily limits in their dispatch data. The requirements for dispatch data are described in Market Rules 6.5 and Market Procedures 17.

Use of stream flow and metrological data

Market Rule 6.1.2 states that the objective function should have regard for any stream flow or meteorological data available. The objective function does not consider this data since the participants are not currently required to supply this information. The requirements for dispatch data are described in Market Rules 6.5 and Market Procedures 17.

Co-Optimization between Energy and Ancillary Services Dispatch

Section 5.3.1 of the existing Market Procedure 18 (System Optimization) briefly describes the optimization of Energy and Ancillary Services. Some clarification of this process is required. The overall system dispatch of Energy and Ancillary Services is carried out in a sequential fashion such that energy is dispatched first followed by each of the capacity based Ancillary Services. A form of simultaneous optimization is carried out only in the event that energy re-dispatch is required in order to free up capacity for a particular capacity based Ancillary Service. If, after Energy optimization, sufficient capacity is available to supply all capacity based Ancillary Service requirements, then the Ancillary Services dispatch is performed using scheduled self-supplied capacity and capacity available at Ancillary Service contract prices only. But if, after the Energy dispatch, there is found to be insufficient capacity of the appropriate type (spinning/non-spinning) and time constant to supply the requirements of a particular capacity based Ancillary Service, then the selection of capacity already dispatched for energy that is to be freed in order to supply the Ancillary service requirement considers both the increase in energy costs of this re-dispatch and the Ancillary Service contract price to be paid for the selection of the capacity to supply the Ancillary Service. A revised Market Procedure 18 to be published will provided greater detail regarding this process.

Submission of revised Balanced Schedules

Market Procedure 16 (Balanced Schedules), section 5, describes the Balanced Schedule submission timing rules for Market Participants and their processing by the NBSO in various time frames. Effective July 1, 2009, new processing rules were implemented by the NBSO and published on its web site. The table "NBSO Schedule

Timing Matrix” below summarizes these new processing rules. To properly reflect these new timing rules, this timing matrix will be integrated into a future amendment to Market Procedure 16.

NBSO Schedule Timing Matrix

Time Evaluated	New Schedule	Modification To Existing
Day Ahead before 11:00	Accept	Accept
Day Ahead after 11:00	Accept	Accept
Day Ahead after 13:00	Reject	Wait
Day Ahead after 18:00	Wait	Accept
30 minutes before the start of the first FHCS run that impacts the Dispatch Day.	Accept	Accept
Less than N minutes before the hour (See Note 1)	Not Allowed	Not Allowed

Where:

- Accept - the submission is accepted for further review. the submission may be rejected if it fails checkout.
- Reject - the submission is rejected.
- Wait - the submission is not evaluated until the next block of time.
- Not Allowed - submissions within the N minutes (See Note 1) of the hour being changed may not be created.
- Maritimes Area includes New Brunswick, Prince Edward Island, Nova Scotia and Northern Maine ISA.
- FHCS runs impact 4 hours into the future

Note 1:

N	Interface
30	MAINE_N
30	MAINE_S
30	NB
60	NEW_ENG
30	NS
30	PEI
30	QUEBEC

Scheduling and Dispatch Objective

Further descriptions of the NBSO dispatch objective and related constraints including mathematical formulations in the form of revised draft Market Procedure 18 are contained in **Appendix B**.

Exhibit B: Additional Information provided by NBSO

The following information was provided by the NBSO management as their response to the exception reported in our Independent Reviewer's Report.

Details of Transmission Congestion Exception

In February 2007, the NBSO released into production an enhancement of its regulation dispatch algorithm. The new algorithm included the capability of dispatching both positive and negative regulation (AGC) capacity, as well as, AGC range limits on facilities. PwC recently completed a market rules compliance review of the NBSO's Market Optimization and Dispatch (MOD) application and determined the AGC dispatch algorithm did not function as designed. Under certain unique conditions, the combination of energy and AGC capacity dispatched by MOD on a generation plant could exceed the transmission constrained maximum for that plant. The unique conditions were:

- The plant, or a unit of the plant, was capable of supplying AGC capacity and had a contract with the NBSO to supply this capacity
- The output of the plant was limited by a transmission constraint
- Re-dispatch of energy was required in order to free up sufficient AGC capacity to meet system requirements

An analysis of MOD dispatch results from the time when the problem was introduced until the problem was mitigated indicated that the set of conditions required to trigger this exception did not occur until September, 2009, and was evident in a number of hours in late September, 2009 and early October, 2009 until its discovery and mitigation in mid-October, 2009. This exception was corrected in MOD by ensuring that any transmission constraints imposed on generation facilities are respected during the energy re-dispatch for AGC and AGC capacity dispatch processes, as they are during other energy and Ancillary Service capacity dispatches performed by MOD.

Whereas, the market settlement process had not yet been completed for the month of October, 2009 when the exception was identified and corrected, all affected day-ahead and hour-ahead MOD runs were re-run for the month of October. Through its investigations the NBSO determined the impact of the September 2009 hours on market settlement data was not of sufficient magnitude to warrant re-runs and resultant adjustments. Although relatively few hours were impacted by the exception, it is important to note the reliability of the NBSO-controlled grid was not impacted by this exception. MOD outputs are primarily utilized in the NBSO's settlement processes and it is not used in the real-time operation of the power system.

A subsequent review of the revised dispatch results for impacted hours of the October 6, 2009 test day was carried out by PwC and they did not note any instances in the revised dispatch results where the transmission constraints in the above noted situation were not respected.

Section III: Scope & Methodology

Scope of Review

The MOD application is a sub-system within NBSO's Market Management System and therefore, interfaces with various other applications in order to obtain inputs required for the scheduling and dispatch objective. Figure 1 below illustrates the various interfaces of the MOD application in relation to the suite of MMS tools.

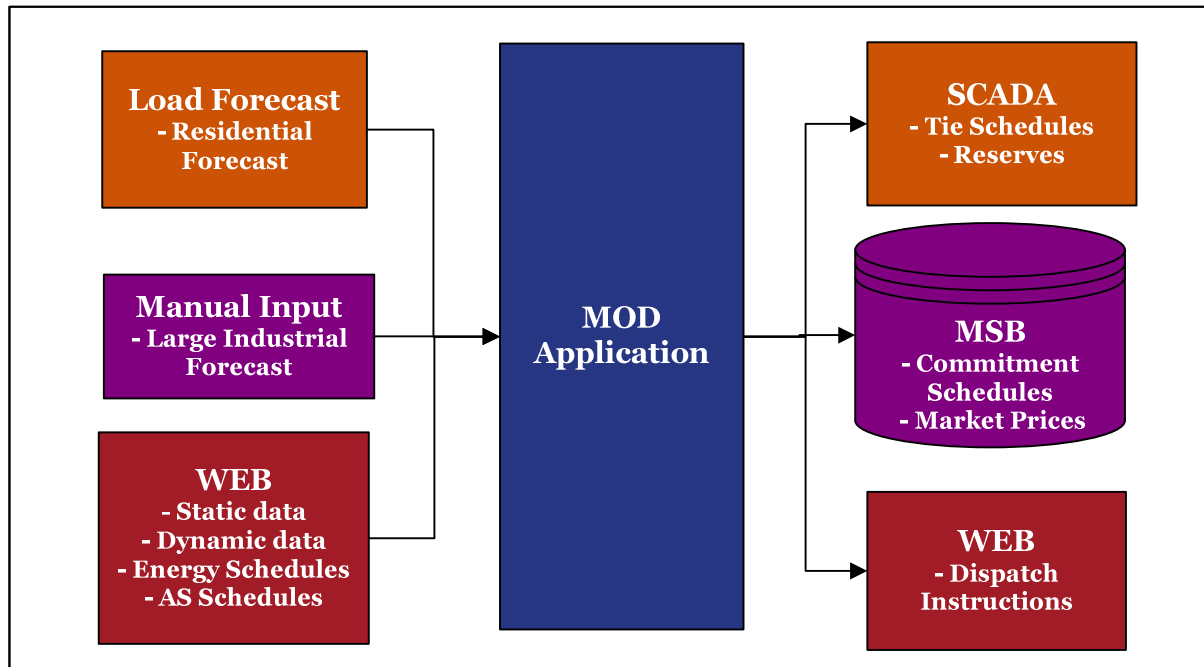


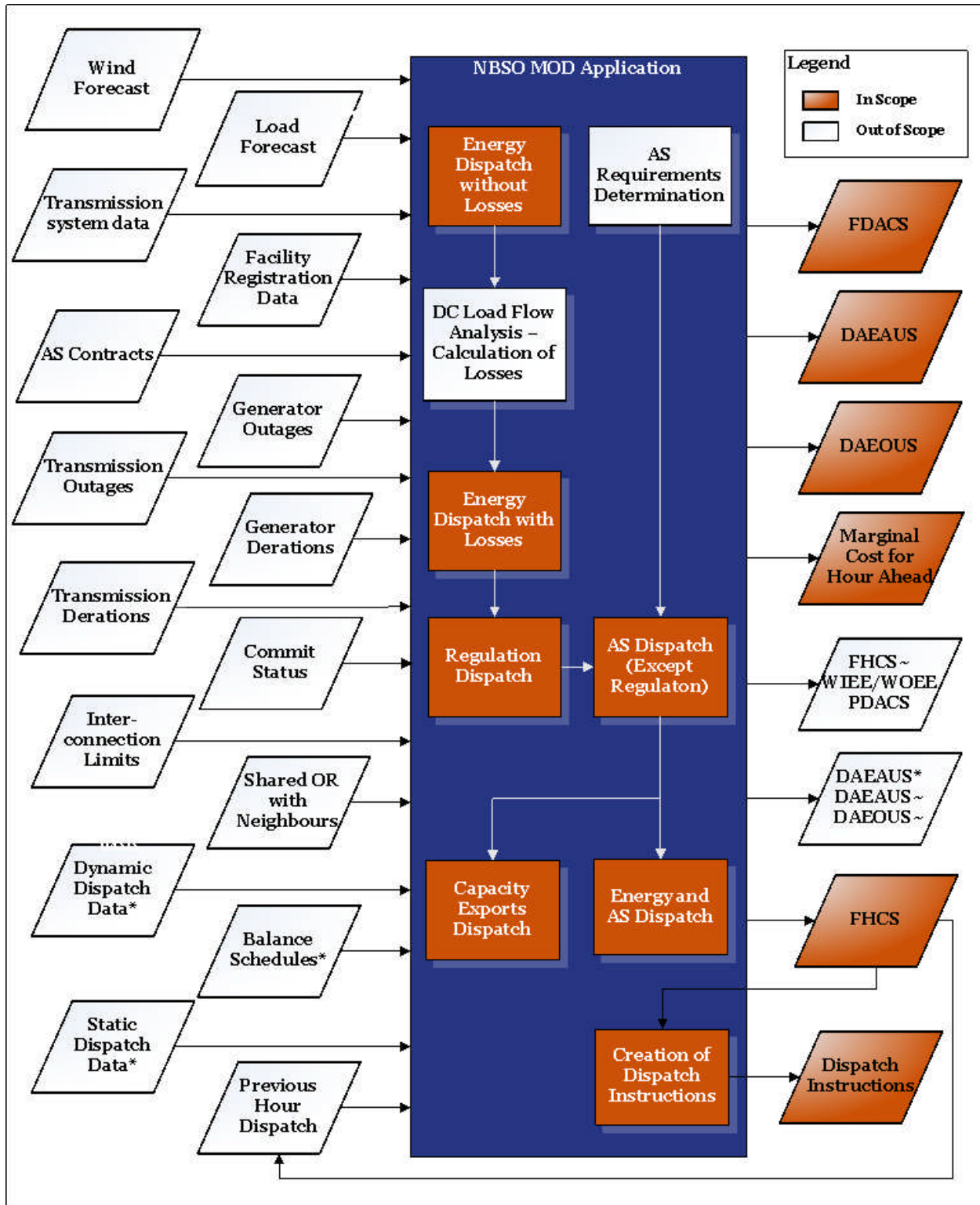
Figure 1 – Overview of MOD Application

Additionally, there are processes within the MOD application that form inputs into the dispatch objective; these include DC load flow analysis to calculate transmission losses and the determination of Ancillary Service requirements. The completeness, accuracy and validity of these inputs was outside the scope of our review. In our analysis, we used these inputs as provided by the NBSO.

A portion of the input data, specifically the Balanced Schedules, static Dispatch Data and dynamic Dispatch Data, were reviewed, however, the scope of the review was only in the context of Market Rules 6.4 – 6.10. This included procedures relating to form and effect of the data, requirements for submission and revisions and treatment of the data by the NBSO.

Additionally, the NBSO utilizes the MOD application to produce various outputs at different times as outlined in **Appendix A** of the report. Based on our understanding of the various optimizations and discussion with the NBSO, the Final Day Ahead Commitment Schedule (FDACS), Final Hourly Commitment Schedule (FHCS), Day Ahead Energy and Ancillaries Unconstrained Schedule (DAEAUS) and Day Ahead Energy Only Unconstrained Schedule (DAEOUS) were included within the scope of the review as these optimizations form the basis for the final commitment schedules, creation of Dispatch Instructions and market settlement.

Figure 2 below describes the inputs, outputs and the internal processes for the dispatch objective and our scope of coverage.



*Reviewed in the context of Market Rules 6.4 - 6.10

Figure 2 – PwC Scope of Coverage

PwC Methodology - Approach

Our review was completed in accordance with Canadian Institute of Chartered Accountants Handbook Section 8600 – Review of Compliance with Agreements and Regulations. As such, our review consisted of the following activities:

- Review of the Market Rules and Market Procedures that govern the operation of the dispatch algorithm and scheduling process; see **Appendix C** for the market rules that were in effect at the time of the review
- Enquiry with NBSO personnel responsible for the use, maintenance, and monitoring of the MOD application
- Assess the adequacy of the descriptions contained within the Market Rules and Market Procedures and where required, obtain interpretations from NBSO management
- Assess the consistency of the application of the Market Rules and management interpretations within the MOD application

To assess the application of the scheduling and dispatch objective within the MOD application, we tested each interval of our test day, October 6, 2009, using Audit Command Language (ACL) to i) identify any dispatches scheduled by the MOD application that would materially violate the constraints of the dispatch algorithm; ii) identify dispatches that were not economic given the marginal cost and system constraints and iii) identify offers below the marginal cost that were not dispatched and not subject to constraints. These tests were created for both the constrained and the unconstrained optimization processes. Any actual material exceptions resulting from these tests are disclosed in our Independent Reviewer's Report in Section II of this report.

For a number of the constraints that were not encountered on our test day, such as a tie breaking between two generators and transmission must run constraint due to congestion, we worked with NBSO staff to create those scenarios (base case scenarios) within their MOD test environment. For this, we used the same input data as our test day, modified the required inputs to create the scenario and assessed whether the outcome matched our expectations.

Appendix A

MOD Optimization Outputs

The MOD application can be utilized to execute constrained and unconstrained optimizations at various time frames to produce one of the following:

- **Preliminary Day Ahead Commitment Schedule (PDACS)** – PDACS is a constrained day-ahead optimization schedule that provides an initial assessment of the adequacy of energy resources for the dispatch day.
- **Final Day Ahead Commitment Schedule (FDACS)** – FDACS provides market participants with a final commitment schedule for their generation facilities based on which generation facilities can prepare for their schedule generation and Ancillary Services supply requirements.
- **Final Hourly Commitment Schedule (FHCS)** – This is the real-time optimization utilizing the latest information in order to produce a schedule for the next dispatch hour. The resulting schedule from FHCS is used in the creation of Dispatch Instructions for generation facilities.
- **Day Ahead Energy and Ancillaries Unconstrained Schedule (DAEAUS)** – DAEAUS is used in market settlement to determine the energy re-dispatch costs resulting from transmission system constraints.
- **Day Ahead Energy Only Unconstrained Schedule (DAEOUS)** – DAEOUS is used in market settlement to determine the energy re-dispatch costs resulting from the impact of ancillary services dispatch.
- **DAEAUS*** – used in market settlement to evaluate the impact of shortfall in self-supply operating reserve on energy re-dispatch costs
- **DAEAUS~** – used in market settlement to evaluate impact of wind facilities on energy re-dispatch costs.
- **DAEOUS~** – used in market settlement to evaluate impact of excess Regulation and Load Following self-supply on energy re-dispatch costs.
- **FHCS~** – used in market settlement to evaluate impact of procurement costs for the purchase of Regulation and Load Following requirements.
- **Final Hourly Commitment Schedule with/without Emergency Energy Sales (WIEE/WOEE)** – used in market settlements to determine the cost of emergency energy exports.

Appendix B

Draft Market Procedure 18

New Brunswick System Operator Market Procedure

MP-18

System Optimization

Issue 02

Effective Date: DRAFT

Contents

Part 1 Document Control

- 1.1 Change history
- 1.2 Contact for queries and submissions
- 1.3 Authority for Market Procedures
- 1.4 Relationship with Market Rules and Transmission Tariff
- 1.5 Definitions and terminology
- 1.6 Updating this Market Procedure

Part 2 Introduction

- 2.1 Purpose of this Market Procedure
- 2.2 Purpose of system optimization and overview of optimization performed
- 2.3 Market Rules references
- 2.4 Scope and application
- 2.5 Responsibilities of parties under this procedure
- 2.6 Other Market Procedures
- 2.7 Form and means of communication
- 2.8 Confidentiality

Part 3 Sources of data

- 3.1 Load forecast data
- 3.2 Transmission system data
- 3.3 Facility registration data
- 3.4 Ancillary Service Contracts
- 3.5 Outage planning and notification
- 3.6 Balanced Schedules
- 3.7 Static Dispatch Data
- 3.8 Dynamic Dispatch Data
- 3.9 Current Hour Dispatch Instructions (hour ahead runs)
- 3.10 Wind Facilities Output Forecasts
- 3.11 Operating Limits of Interconnections
- 3.12 Shared Operating Reserves with Neighbouring Balancing Areas
- 3.13 Operational communications

Part 4 Optimization Runs

- 4.1 Preliminary Day Ahead Commitment Schedule (PDACS)
- 4.2 Final Day Ahead Commitment Schedule (FDACS)
- 4.3 Final Hourly Commitment Schedule (FHCS)
- 4.4 Day Ahead Energy and Ancillaries Unconstrained Schedule (DAEAUS)
- 4.5 Day Ahead Energy and Ancillaries Unconstrained Schedule * (DAEAUS*)
- 4.6 Day Ahead Energy and Ancillaries Unconstrained Schedule ~ (DAEAUS~)
- 4.7 Day Ahead Energy Only Unconstrained Schedule (DAEOUS)

- 4.8 Day Ahead Energy Only Unconstrained Schedule ~ (DAEOUS~)
- 4.9 Final Hourly Commitment Schedule ~ (FHCS~)
- 4.10 Final Hourly Commitment Schedule With Emergency Energy Sales (WIEE)
- 4.11 Final Hourly Commitment Schedule Without Emergency Energy Sales (WOEE)

Part 5 Optimization Methodology

- 5.1 Energy Dispatch
- 5.2 Ancillary Service optimization

Part 6 Optimization Outputs

- 6.1 Provisional and Final Day Ahead Commitment Schedules
- 6.2 Final Hourly Commitment Schedule

Part 7 Flow Chart

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Part 1 Document Control

1.1 Change History

Issue	Date	Reason for Issue
Discussion document	2004 09 16	Pre-market Publication
01	2006 04 01	Post-market Publication

1.2 Contact for queries and submissions

For queries concerning the application or interpretation of this Market Procedure, contact:

Name: NBSO Power System Operations

Phone: 506 458 4656

Address: P.O. 2020
77 Canada Street
Fredericton
New Brunswick
E3B 5G4

e-mail: info@nbsso.ca

Website : www.nbsso.ca

All documents required to be submitted to the SO under this Market Procedure must be submitted to the attention of this contact person at the coordinates noted above in accordance with the requirements of section 2.7.

1.3 Authority for Market Procedures

This Market Procedure is made under the authority of section 3.3 of the Market Rules.

1.4 Relationship with Market Rules and Transmission Tariff

Nothing in this Market Procedure supersedes or over-rides any provision of the Market Rules or of the Transmission Tariff. Where there is a discrepancy between the requirements in this Market Procedure and the Market Rules, the Market Rules prevail. Similarly, where there is a discrepancy between the requirements in this Market Procedure and the Transmission Tariff, the Transmission Tariff prevails. Any user of this Market Procedure who identifies any discrepancy between this Market Procedure and either the Market Rules or the Transmission Tariff should notify the contact person identified in section 1.2.

Any summary of a provision or requirement of the Market Rules or of the Transmission Tariff contained in this Market Procedure is provided for convenience of reference only. Users of this Market Procedure are reminded that the obligations that need to be met are as stated in the Market Rules and the Transmission Tariff.

1.5 Definitions and terminology

Terms capitalized in this Market Procedure that are not otherwise defined in this Market Procedure have the meanings given to them in chapter 10 of the Market Rules. The rules of interpretation contained in chapter 10 of the Market Rules apply to this Market Procedure, with such modifications as the context may require.

This Market Procedure should be read in conjunction with Market Procedure MP-00, which specifies certain terminology common to all Market Procedures.

1.6 Updating this Market Procedure

Changes may from time to time be made to this Market Procedure in accordance with the Market Rules. All such changes will be Published by the SO but may not yet be included in a consolidated version of this Market Procedure. It is the responsibility of each user of this Market Procedure to use the most up-to-date information and documents. Users wishing confirmation of any changes to this Market Procedure that have not yet been incorporated into this consolidation should contact the person identified in section 1.2.

Part 2 Introduction

2.1 Purpose of this Market Procedure

The purpose of this Market Procedure is to help Market Participants and others to understand the optimization process normally undertaken by the SO in managing the Integrated Electricity System, and used by the SO as a basis for the development of Commitment Schedules and Dispatch Instructions.

This Market Procedure only comes into effect following the Systems Implementation Date.

2.2 Purpose of System Optimization and overview of optimization performed

The purpose of system optimization is the economical scheduling and dispatch of resources available to the SO and the SO-controlled Grid to fulfill the objectives set out in sections 6.1.1 of the Market Rules, in accordance with section 6.1.2 of the Market Rules.

The SO uses the results of its system optimization as a basis for the development of Commitment Schedules and Dispatch Instructions.

Optimization is first undertaken on the Day Ahead. All Day Ahead optimization considers the full 24 hours of the Dispatch Day. Day Ahead optimization will consider transmission constraints, Facility capabilities, and marginal transmission line losses. This optimization is used as a basis for the Provisional Commitment Schedule and the Final Day Ahead Commitment Schedule (FDACS). The FDACS is then used as the basis of Facility commitment, settlement of redispatch costs associated with Ancillary Services provided to the SO, and determination of congestion management re-dispatch costs.

In the last hour before the start of the Dispatch Day and hourly throughout the Dispatch Day, the system optimization is re-run on the basis of the most current data set for the next four hours in the Dispatch Day. This optimization is used as the basis of the Final Hourly Commitment Schedule for the next hour.

2.3 Market Rules references

Section 6.1 of the Market Rules sets out the scheduling and dispatch objectives.

2.4 Scope and application

This Market Procedure is purely descriptive of activities undertaken by the SO.

2.5 Responsibilities of parties under this procedure

This Market Procedure does not create any obligation on the SO or any other party.

2.6 Other Market Procedures

The optimization process draws on inputs described in several other Market Procedures, including in particular:

- MP-03, Facility Registration
- MP-13, Outage Planning and Approval
- MP-16, Balanced Schedules
- MP-17, Dispatch Data
- MP-20, Forced Outages

Outputs from this optimization process are used by the SO in the development of Dispatch Instructions as described in Market Procedure MP-19.

2.7 Form and means of communication

There are no communications under this Market Procedure:

2.8 Confidentiality

While the optimization process is described in this Market Procedure, the software code is confidential, many inputs are confidential to particular Market Participants, and the Commitment Schedules and Dispatch Instructions that are based on its output are also confidential to particular Market Participants.

2.9 Interim and Deferred Provisions

As noted in section 2.1 above, this Market Procedure only comes into effect following the Systems Implementation Date.

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Part 3 Sources of Data

3.1 Load forecast data

3.1.1 All system optimization is performed on the basis of the SO's load forecasts for New Brunswick. These load forecasts are published at certain set times in accordance with section 6.3 of the Market Rules, and are updated by the SO for its internal use as it sees appropriate.

3.2 Transmission system data

3.2.1 Data on transmission systems is required to be provided to the SO by Transmitters under the terms of their Operating Agreements with the SO.

3.2.2 Such data includes the system configuration and the limits and transmission characteristics applicable to each element.

3.3 Facility Registration data

3.3.1 For thermal and "other" Facilities the registration data is used in defining the normal operating limits of the Facility, including:

- minimum continuous operating output,
 - normal operating ramp rates (including any hold points),
 - maximum continuous rating,
- all under an appropriate range of conditions.

3.3.2 For hydraulic Facilities, the registration data is used in defining the normal operating limits of each unit within the Facility and includes:

- minimum continuous operating output,
 - normal operating ramp rates,
 - maximum continuous rating,
- all under an appropriate range of conditions.

3.3.3 For wind Facilities, the registration data is used in defining the normal operating limits of the Facility:

- minimum continuous operating output,
 - maximum continuous rating,
- all under an appropriate range of conditions.

3.4 Ancillary Services Contracts

3.4.1 Ancillary Services Contracts attachments, provide in respect of each relevant Facility:

- Limits on the quantity of each Ancillary Service available under the contract
- Operating Range data including ramp rates (which may be different for each Ancillary Service)
- Price data per unit of each Ancillary Service

3.5 Outage planning and notification

3.5.1 The SO's outage planning system contains data on

- planned transmission system outages which may cause constraints in operation of the transmission network or of particular connections, and
- planned outages of Generation Facilities which may affect Facility capabilities.

- 3.5.2 The SO also relies on receipt of prompt notification of Forced Outages in respect of transmission elements and of Generation Facilities. Such notification of Forced Outages may place limits on Generation Facility operation that are not yet reflected in Dispatch Data.
- 3.5.3 Each optimization run uses the latest accepted submissions and revisions of outage planning and notifications, except those identified in Part 4 below as day-ahead runs purely for settlement purposes, which are based on the same data set as the FDACS.

3.6 Balanced Schedules

- 3.6.1 Balanced Schedules in respect of imports and exports (including wheels) provide data on the injections and withdrawals to be scheduled at the Interconnections, and thus on the demand to be served by New Brunswick generation. Status information with regard to export schedules (firm/non-firm, unit contingent/non-unit contingent, etc) is also used in determining whether a given export schedule can be Operating Reserve requirements and thus reduce the scheduling requirements from SO controlled generators.
- 3.6.2 Balanced Schedules in respect of self-supplied Ancillary Services identify that the Ancillary Services thus scheduled are provided to the SO at no cost to the SO.
- 3.6.3 Balanced Schedules in respect of capacity exports identify Operating Reserve capacity that must be scheduled from SO controlled generators in addition to that scheduled for the SO balancing area.
- 3.6.4 Balanced Schedules in respect of capacity imports identify Operating Reserve capacity that can be used to reduce Operating Reserve scheduling requirements from SO controlled generators.
- 3.6.5 Each optimization run uses the latest accepted submissions and revisions of Balanced Schedules, except those identified in Part 4 below as day-ahead runs purely for settlement purposes, which are based on the same data set as the FDACS.

3.7 Static Dispatch Data

- 3.7.1 Static Dispatch Data provides start-up data, ramp rates, and minimum run data used by the SO in Day Ahead optimization and declining-balance-of-day optimization.
- 3.7.2 Each optimization run uses the latest accepted Static Data, except those identified in Part 4 below as day-ahead runs purely for settlement purposes, which are based on the same data set as the FDACS.

3.8 Dynamic Dispatch Data

- 3.8.1 Dynamic Dispatch Data provide the incremental energy price information for use in all optimization by the SO.
- 3.8.2 Each optimization run uses the latest accepted Dispatch Data, except those identified in Part 4 below as day-ahead runs purely for settlement purposes, which are based on the same data set as the FDACS

3.9 Current Hour Dispatch Instructions (hour ahead runs)

- 3.9.1 For hour ahead runs, current hour generation facility Dispatch Instructions are used in setting both up and down ramping constraints for the generation facilities in the dispatch hour and subsequent hours in the run.

3.10 Wind Facilities Output Forecasts

3.10.1 Forecast of anticipated hourly facility energy output for each registered Wind facility. Forecasts may be based on the results of detailed wind facility output forecasts, persistence methodology, balanced schedule data or manually input forecasts as appropriate for the facility.

3.11 Operating Limits of Interconnections

3.11.1, Operating limits of Interconnections may be adjusted (and in particular lowered) by the appropriate Control Authority or system operator.

3.12 Shared Operating Reserves with Neighbouring Balancing Areas

3.12.1 The quantity of shared operating reserve made available by neighbouring balancing areas can be used to reduce the dispatch requirement for operating reserve from SO controlled generators

3.13 Operational communications

3.13.1 Operational communications will generally impact on real time operations rather than on system optimization. There may however be occasions when operational communications contain information that is relevant in the optimization time frame but is not yet reflected in other data (eg as a Forced Outage report).

Part 4 Optimization Runs

The SO must execute a number of optimization runs in various time frames and for various purposes, including:

- Day-ahead runs
- Hour-ahead runs
- Various other specialized runs that provide input to the Market settlement process

Each of these optimization runs uses the same system model and optimization methodology but differ in time frame, specific inputs used or constraints applied.

4.1 Preliminary Day Ahead Commitment Schedule (PDACS)

4.1.1 The PDACS optimization run is a day-ahead run that provides an initial assessment of the adequacy of energy and capacity resources for the dispatch day and also provides generation facility owners with a preliminary commitment schedule for their generation facilities. Run characteristics include:

- Run between 13:00 and 14:00 on the previous business day to the dispatch day for all hours in the dispatch day
- Uses provisional Dispatch Data, provisional Balanced and interchange schedules, load forecast data and generation facility and transmission element outage/limitation data
- Applies all transmission constraints in effect during the dispatch day
- Includes all system ancillary service requirements

Based on this preliminary commitment schedule, market participants then have an opportunity to adjust generation facility Dispatch Data and energy and ancillary service schedules prior to the Final Day Ahead Commitment Schedule (FDACS) optimization run.

4.2 Final Day Ahead Commitment Schedule (FDACS)

4.2.1 The FDACS optimization run is a day-ahead run that provides a final assessment of the adequacy of energy and capacity resources for the dispatch day and also provides generation facility owners with a final commitment schedule for their generation facilities. Run characteristics include:

- Run between 15:00 and 16:00 on the previous business day to the dispatch day for all hours in the dispatch day
- Uses Final Day Ahead Dispatch Data, Final Day Ahead Balanced and interchange schedules, load forecast data and generation facility and transmission element outage/limitation data
- Applies all transmission constraints in effect during the dispatch day
- Includes all system ancillary service requirements

Based on this final day ahead commitment schedule, generation facilities can then prepare for their scheduled generation and Ancillary Service supply requirements, and marketers are informed as to which Facilities are expected to be committed and not committed so that they may seek out additional sales opportunities.

4.3 Final Hourly Commitment Schedule (FHCS)

- 4.3.1 The FHCS optimization run is an hour-ahead run that uses the latest information available regarding forecasted system load, Balanced Schedules, transmission outages, and Generation Facility capabilities and Dispatch Data in producing a generator commitment schedule for the next dispatch hour and a preliminary commitment schedule for up to three additional hours. Run characteristics include:
- Run between 25 minutes and 10 minutes prior to the dispatch hour for the dispatch hour and up to three additional hours
 - Uses latest Dispatch Data, Balanced and interchange schedules, load forecast data and generation facility and transmission element outage/limitation data
 - Applies all transmission constraints in effect during the dispatch day
 - Includes all system ancillary service requirements

The resulting energy commitment schedules are used in the creation of Dispatch Instructions for Generation Facilities and the ancillary service commitment schedules are used in determining payments to generation facilities for ancillary services procurement.

4.4 Day Ahead Energy and Ancillaries Unconstrained Schedule (DAEAUS)

- 4.4.1 The DAEAUS optimization run is used in market settlement in evaluating the energy redispatch costs resulting from transmission system constraints. Run characteristics include:

- Run after FDACS run as part of settlement process
- Uses model data identical to that used by the FDACS day ahead run, but removing all constraints imposed by the transmission system that were in effect for the FDACS run. These constraints include:
 - All normal or reduced transmission model element limits
 - All transmission model element outages
 - All generation facilities that were committed on in the FDACS run because of transmission system constraints are committed off, or, in the case of facilities that can be committed as required during optimization, allowed to commit as required
 - All generation facilities that were committed off in the FDACS run because of transmission system constraints are committed on, or, in the case of facilities that can be committed as required during optimization, allowed to commit as required
 - All generation facility derations due to transmission system constraints are removed
- Includes all system ancillary service requirements

In market settlement, the difference in the energy costs for each hour between the DAEAUS run and that for the FDACS is used as the energy redispatch cost of transmission congestion (Congestion Management Cost) for that hour.

4.5 Day Ahead Energy and Ancillaries Unconstrained Schedule * (DAEAUS*)

- 4.5.1 The DAEAUS* optimization run is used in market settlement in evaluating the energy redispatch costs resulting from any shortfall in the self-supply of incremental operating

reserve by market participants with incremental operating reserve scheduling obligations. Run characteristics include:

- Run after FDACS run as part of settlement process
- Uses model data identical to that used by the FDACS day ahead run, but removing the following:
 - All constraints imposed by the transmission system that were in effect for the FDACS run (as with DAEAUS run)
 - Any incremental operating reserve requirements that have not been self-supplied by the obligated market participant

In market settlement, the difference in the energy costs for each hour between the DAEAUS* run and that for the DAEAUS is used as the energy redispatch cost of incremental operating reserve scheduling shortfall for that hour.

4.6 Day Ahead Energy and Ancillaries Unconstrained Schedule ~ (DAEAUS~)

4.6.1 The DAEAUS~ optimization run is used in market settlement in evaluating the energy redispatch costs resulting from the impact of wind facilities on system Regulation and Load Following requirements that have not been self-supplied by wind facilities. Run characteristics include:

- Run after FDACS run as part of settlement process
- Uses model data identical to that used by the FDACS day ahead run, but removing the following:
 - All constraints imposed by the transmission system that were in effect for the FDACS run (as with DAEAUS run)
 - Any incremental operating reserve requirements that have not been self-supplied by the obligated market participant (as with DAEAUS* run)
 - Any system Regulation and Load Following requirements attributed to wind facilities that has not been self supplied by wind facilities

In market settlement, the difference in the energy costs for each hour between the DAEAUS~ run and that for the DAEAUS* is used as the energy redispatch cost resulting from the impact of wind facilities on system Regulation and Load Following requirements that have not been self-supplied by wind facilities for that hour.

4.7 Day Ahead Energy Only Unconstrained Schedule (DAEOUS)

4.7.1 The DAEOUS optimization run is used in market settlement in evaluating the energy redispatch costs resulting from the impact of load facilities on system capacity based ancillary service requirements that have not been self-supplied by load facilities. Run characteristics include:

- Run after FDACS run as part of settlement process
- Uses model data identical to that used by the FDACS day ahead run, but removing the following:
 - All constraints imposed by the transmission system that were in effect for the FDACS run (as with DAEAUS run)
 - Any incremental operating reserve requirements that have not been self-supplied by the obligated market participant (as with DAEAUS* run)

- Any system capacity based ancillary service requirements that have not been self supplied

In market settlement, the difference in the energy costs for each hour between the DAEOUS run and that for the DAEAUS~ is used as the energy redispatch cost resulting from the impact of load facilities on system capacity based ancillary service requirements requirements that have not been self-supplied by market participants for that hour.

4.8 Day Ahead Energy Only Unconstrained Schedule ~ (DAEOUS~)

4.8.1 The DAEOUS~ optimization run is used in market settlement in evaluating the energy redispatch costs resulting from the impact of excess Regulation and Load Following self-supply from wind facilities above system Regulation and Load Following requirements attributed to wind facilities. Run characteristics include:

- Run after FDACS run as part of settlement process
- Uses model data identical to that used by the FDACS day ahead run, but removing the following:
 - All constraints imposed by the transmission system that were in effect for the FDACS run (as with DAEAUS run)
 - Any incremental operating reserve requirements that have not been self-supplied by the obligated market participant (as with DAEAUS* run)
 - Any system capacity based ancillary service requirements that have not been self supplied (as with DAEOUS run)
 - Any Regulation and Load Following self-supply from wind facilities that exceeds system requirements for these ancillary services attributed to wind facilities

In market settlement, the difference in the energy costs for each hour between the DAEOUS~ run and that for the DAEOUS is used as the energy redispatch cost resulting from the impact of excess Regulation and Load Following self-supply from wind facilities above system Regulation and Load Following requirements attributed to wind facilities.

4.9 Final Hourly Commitment Schedule ~ (FHCS~)

4.9.1 The FHC~ optimization run is used in market settlement in determining the procurement costs for the purchase of system Regulation and Load Following requirements that is attributed to wind facilities. Run characteristics include:

- Run for each hour of a dispatch day after FHCS run as part of settlement process
- Uses model data identical to that used by the FHCS hour ahead run, but removing the following:
 - Any system Regulation and Load Following requirements attributed to wind facilities

In market settlement, the difference between the ancillary service procurements costs for the FHC~ run and that of the FHCS run is used as the change in procurement costs due to wind facilities while the remaining procurement costs are used as the procurement costs attributed to load facilities.

4.10 Final Hourly Commitment Schedule With Emergency Energy Sales (WIEE)

4.10.1 The WIEE optimization run is used in market settlement in conjunction with the WOEE optimization run in determining the cost of emergency energy exports. The WIEE run is essentially a 24 hour FHCS run that is run after the dispatch day is completed and uses the latest information available regarding forecasted system load, Balanced Schedules (including the latest emergency energy export schedules), transmission outages, and Generation Facility capabilities and Dispatch Data. Run characteristics include:

- Run for all hour of a dispatch day
- Includes all transmission constraints
- Includes all ancillary service requirements

4.11 Final Hourly Commitment Schedule Without Emergency Energy Sales (WOEE)

4.11.1 The WOEE optimization run is used in market settlement in conjunction with the WIEE optimization run in determining the cost of emergency energy exports. Run characteristics include:

- Run for all hour of a dispatch day
- Includes all transmission constraints
- Includes all ancillary service requirements
- Uses model data identical to that used by the WIEE run, but removing the following:
 - All emergency energy exports scheduled

In market settlement, the difference between the energy costs for the WOEE run and that of the WIEE run is used as the supply cost for emergency energy exports.

Part 5 Optimization Methodology

Each of the various optimization runs described in Part 4 performs a System Dispatch for both energy and capacity based ancillary services for each hour within the dispatch period for that run. The following sections describe the methodology used.

5.1 Hour Dispatch Ordering

The hours in an optimization run are dispatched in the following order:

- Peak hour
- (Hour Peak hour – 1) to 1'st hour of run by -1
- (Hour Peak hour + 1) to last hour of run by +1

The peak hour is defined as the hour with the largest total net load

$$= \text{In-province Load} + \text{SUM (Interface net exports)}.$$

The peak hour energy dispatch is not ramp rate constrained by adjacent already dispatched hours (other than by the Dispatch Instructions for the hour previous to the first dispatch hour). All other hours are ramp rate constrained by the adjacent already dispatched hour.

5.2 Hour Dispatch

The dispatch for a particular optimization run hour involves the following steps:

- i. Initialization
- ii. CT commitment System Dispatch
- iii. Final System Dispatch if required

5.3 Hour Initialization

Hour initialization involves the following:

- i. Setting up the transmission model in effect for hour, including any transmission line capacity derations or outages.
- ii. Defining all generators available for the hour, plus their characteristics (limits, PQ pairs, ramp rates, transmission model connection points, etc), to the model
- iv. Setting up model loads, including loads based on the SO's system load forecast, loads based on schedules and export loads

5.4 CT Commitment Dispatch

The optimization application performs a limited unit commitment of any generators flagged as may-commit (principally CTs), bringing them on-line if required for energy or spinning reserve, or if the deemed cost of starting the facility and supplying energy is less than the PQ cost of competing on-line generators. The May-Commit Generator Commitment Dispatch involves the following steps:

- Modify the characteristics of available may-commit generators so that MW can be dispatched on these generators if required:
 - Energy minimum = 0
 - PQ pairs extended down to 0 and adjusted to include adders for startup and minimum run
 - Do a System Dispatch for energy, ancillary services and optionally capacity exports
- Check as to whether any may-commit generators were dispatched above 0 and if so, prepare for a 2nd (final) dispatch by configuring available may-commit generators as follows:
 - Restoring original PQ pairs
 - If dispatch level in commit dispatch was < may-commit threshold then the generator is configured off (minimum for energy = 0, maximum for energy = 0)
 - If dispatch level in commit System Dispatch was >= may-commit threshold, restore generator's normal minimum and maximum

5.5 Final Dispatch

Once the CT commitment System Dispatch is completed, a 2nd System Dispatch is performed in order to arrive at the final dispatch if any may-commit generators were dispatched above 0 in the CT commitment System Dispatch. Otherwise the CT commitment System Dispatch becomes the final System Dispatch.

5.6 System Dispatch

Both the CT Commitment System Dispatch and Final System Dispatch perform a full system dispatch using the configuration for the transmission network, available generators, loads and interchanges as set up during hour initialization and adjusted as required for CT Commitment / Final dispatch. This system dispatch includes:

- An energy dispatch
- A dispatch of each capacity based ancillary service in turn
- For day-ahead and settlement runs, a capacity exports dispatch

In cases where the initial energy dispatch leaves insufficient capacity of the appropriate time constants to fully supply a given ancillary service but redispatching energy will provide the required additional capacity, one or more additional energy dispatches are performed with adjusted energy limits in order to make available the desired capacity for the ancillary service. When energy redispatch is required, not only the current but all already dispatched ancillary services are dispatched again as the new energy dispatch may shift the ancillary service capacity already dispatched to portions of generators with different ramp rates than the earlier dispatch, thus resulting in more or less capacity actually available.

If in attempting to dispatch a given ancillary service requirement a capacity shortfall is detected, the requirement for that ancillary service is reduced by the shortfall amount and the dispatch of this ancillary repeated.

5.7 Energy Dispatch

The Energy Dispatch module performs an energy dispatch for the case defined during hour initialization and modified as necessary before the CT commitment and Final System Dispatch steps. For run types that are to consider transmission constraints, this module also:

- Applies transmission constraints to generators
- If necessary, redispatches energy in order to alleviate any minimum interface flow violations

5.7.1 Model Inputs

The model inputs used by the Energy Dispatch module can be categorized as follows:

- Run parameters
 - Ramp rate constrained/unconstrained by previous hour dispatch levels
 - Transmission constrained/unconstrained
- Transmission model
 - Transmission busses
 - Transmission lines & transformers
 - bus connections
 - resistance
 - reactance
 - capacity
- Generators and their characteristics
 - Min and max limits

- Ramp tables
- PQ pairs
- Transmission connection point info
- Adjacent hour dispatch level (ramp rate constrained run)
- Loads and their characteristics
 - Point loads (MW and transmission bus)
 - Distributed loads (MW and bus distribution factors)

5.7.2 Ramp Rate Constrained vs Unconstrained Energy Dispatch

A ramp rate unconstrained Energy Dispatch simply uses the generator energy minimums and maximums from the input model data as constraints in its dispatch. A ramp rate constrained dispatch uses each generator's ramp rate table to determine the ramp up and ramp down levels to which the generator can ramp in 60 minutes from the specified adjacent hour dispatch level, and overrides the corresponding limit from the input model if the ramp rate constrained limit is more restrictive.

5.7.3 Transmission Constrained vs Unconstrained Energy Dispatch

Depending on the characteristics of the particular optimization run, the energy dispatch is performed as either:

- transmission constrained, where:
 - Transmission element outages are reflected in the transmission model
 - Transmission line capacity constraints (normal or de-rated) are loosely respected during the dispatch
 - Interface TTC and minimum tie flow restrictions are respected when dispatching External Dispatchable facilities into the Market (note that scheduled interface flows that exceed these restrictions are permitted to flow), or
- transmission unconstrained, where:
 - transmission line capacity constraints and any transmission element outages are not considered,
 - Interface TTC and minimum tie flow restrictions are not considered in dispatching External Dispatchable facilities
 - Facilities flagged as on-line due to transmission congestion (transmission security constraints) are committed off-line in the model
 - Facilities flagged as off-line due to transmission congestion are committed on-line in the model

5.7.4 Energy Dispatch Objective Function and Constraints

The Energy Dispatch consists of the economic selection of available P/Q Pairs in order to supply the total load requirement.

Available P/Q Pairs for a given generation facility are subject to the following constraints:

- Facility commit status (on, off, availability for commitment)
- Generator rated maximum

- Unit outages/energy derations
- Transmission congestion (transmission constrained runs)
- Maximum facility P/Q Pair Q
- Facility output forecast (wind facilities only)
- Ramping capability from adjacent already dispatched hours

The objective function and constraints for the Energy Dispatch are detailed in sections 5.7.4.2 and 5.7.4.3.

5.7.4.1 Glossary - Energy Optimization

P/Q_Cost	-	The cost of selection of MW from available P/Q pairs forms the Energy Dispatch objective function that is to be minimized, and is represented by P/Q_Cost.
P/Q_Pairs	-	The price/quantity pairs of each committed generator are represented by set P/Q_PAIRS and are indexed by n.
Generators	-	The committed generation facilities are represented by set GENERATORS and are indexed by g.
Ancillaries	-	The five Ancillary Service requirements (AGC, Load Following, Spinning Reserve, Supplemental Reserve, and 30-min Reserve) are represented by set ANCILLARIES and are indexed by j.
P/Q_Pair_Prices	-	The price components for each P/Q Pair are represented by set P/Q_Pair_Prices are indexed by g and n.
Gen_Loss_Factors	-	Generator loss factors equal to (1 - % losses associated with each generator bus) are represented by set Gen_Loss_Factors and are indexed by g.
TieBreakFactor	-	Small factor used to add slight slope to PQ pair prices as MW are dispatched from the PQ pair. This enables balanced loading among generation facilities having equally priced PQ pairs, subject to any transmission penalties.
P/Q_Pair_MW	-	The selected MW amounts from each P/Q Pair are represented by set P/Q_Pair_MW and indexed by g and n.
MRQ	-	The minimum run quantity for each committed generator.
Gen_Max	-	The rated maximum MW output for each generator.
D_Gen_Max	-	The derated maximum MW output for each generator.
Q_Gen_Max	-	The maximum quantity Q from the P/Q Pairs of a generator.
T_Gen_Max	-	The transmission constrained maximum energy output for each generator.
Forecast_Max	-	The forecast energy output from a wind facility for the dispatch hour.
RR_Gen_Max	-	The maximum energy output that can be achieved based on the energy dispatch level in adjacent already dispatched hours
Energy_Load	-	The MW total of all customer loads, including in-province load, interfaces with a net export scheduled, and system losses.
MW_Ramp_H	-	Upper limit of generator MW output using a 60-minute ramp time from previous hour's Dispatch Instruction, not to exceed Gen_Max.

MW_Ramp_L - Lower limit of generator MW output using 60-minute ramp time from previous hour's Dispatch Instruction, not to go below MRQ.

5.7.4.2 Energy Dispatch Objective Function

For the Energy Dispatch objective function, the cost of selection of MW from all available generator P/Q Pairs is minimized, where:

$$P/Q_Cost = \sum_{\{n, g \mid n \in P/Q_PAIRS\}_g, \text{ where } g \in GENERATORS} (P/Q_Pair_Prices)_{g, n} \times (Gen_Loss_Factors)_g \\ \times (P/Q_Pair_MW)_{g, n} \times (1 + TieBreakFactor)$$

This objective function is constrained by the requirement for power balance between total generation and total load where:

$$\sum_{\{n, g \mid n \in P/Q_PAIRS\}_g, \text{ where } g \in GENERATORS} (P/Q_Pair_MW)_{g, n} + \sum MRQ_g = Energy_Load$$

Other constraints are summarized in section 5.1.4.

5.7.4.3 Energy Dispatch Constraints

5.7.4.3.1 Facility Commit Status

P/Q Pairs from committed generators are available for selection while those from uncommitted generators are not available for selection of MW.

5.7.4.3.2 Generator Rated Maximum

The selected MW from P/Q Pairs on a generator, plus the MRQ of that generator, are limited by the generator's rated maximum less any capacity already allocated for capacity based Ancillary Services (in the case where energy re-dispatch is required during Ancillary Services dispatch)

$$\sum (P/Q_Pair_MW)_{g, n} + MRQ_g \leq Gen_Max_g - AS_MW_g$$

For the initial Energy Dispatch, $AS_MW_g = 0$.

5.7.4.3.3 Unit Outages/Derations

P/Q Pairs from generators on outage are not available for selection of MW.

For a partial outage, or deration, the selected MW from P/Q Pairs on a generator, plus the MRQ of that generator, must be less than or equal to its derated maximum.

$$\Sigma (P/Q_Pair_MW)_{g,n} + MRQ_g \leq D_Gen_Max_g$$

5.7.4.3.4 Transmission Congestion

For optimization runs that are transmission constrained, the available MW from each P/Q Pair is subjected to load flow analysis in order to determine both Gen_Loss_Factors and whether any transmission constraints would limit the selection of MW from any generator. For dispatchable facilities external to the SO controlled grid, available P/Q pairs are also subject to any interface import TTC and minimum tie flow limitations.

$$\Sigma (P/Q_Pair_MW)_{g,n} + MRQ_g \leq T_Gen_Max_g$$

For energy optimization runs that are not transmission constrained, T_Gen_Max is set to large (non-constraining).

5.7.4.3.5 Facility Maximum P/Q Pair Q

The maximum P/Q pair Q value represents the maximum MW offered to the Market by the facility and therefore limits the MW that is available from the facility.

$$\Sigma (P/Q_Pair_MW)_{g,n} + MRQ_g \leq Q_Gen_Max_g$$

5.7.4.3.6 Facility Output Forecast (Wind Facilities Only)

For wind facilities only, the SO output forecast for the facility is a further limitation on the maximum energy output that can be dispatched on the facility.

$$Gen_Max_g = Forecast_Max_g$$

5.7.4.3.7 Facility Ramping Capability

A facility's minimum and maximum energy dispatch limits are constrained by the facility's ramping capability (based on its ramp rate table) from both:

- The Dispatch Instruction level for the hour previous to the Dispatch Hour (hour-ahead run) or commitment schedule level for the hour previous to the first Dispatch Hour (day-ahead runs)
- The dispatch level for any already dispatched hours that are adjacent to the Dispatch Hour

$$\Sigma (P/Q_Pair_MW)_{g,n} + MRQ_g \leq MW_Ramp_H_g$$

$$\Sigma (P/Q_Pair_MW)_{g,n} + MRQ_g \geq MW_Ramp_L_g$$

5.8 Ancillary Services Dispatch

Once the system has been dispatched for energy, generation capacity is then dispatched for each of the required capacity based Ancillary Services in turn. Additional energy dispatches may be required to move energy between generators if sufficient capacity of the required time constant is not available, or ancillary service dispatch requirements may be reduced if the system is actually capacity deficient. For optimization run types that are to consider transmission constraints, this module also applies transmission constraints on generators.

5.8.1 Calculation of Ancillary Service Requirements

Prior to performing the Ancillaries Dispatch, capacity requirements must be calculated for the following:

- AGC
- Load Following
- Spinning Reserve
- Supplemental Reserve
- 30-min Reserve

These capacity calculations are consistent with *NPCC Document A-06 Operating Reserve Criteria December 29, 2008*.

The selection of generation capacity to meet these Ancillary Service requirements is the basis of the Ancillaries Dispatch, and is detailed in section 5.8.4.

5.8.2 Model Inputs

The model inputs used by the Ancillary Service Dispatch module can be categorized as follows:

- Run parameters
 - Transmission constrained/unconstrained
- Transmission model
 - Transmission busses
 - Transmission lines & transformers
 - bus connections
 - capacity
- Generators and their characteristics
 - Min and max limits
 - For Regulation, Regulation range limits
 - Energy Dispatch MW level
 - Operating Reserve capability when offline but available
 - Quickstart status
 - Ramp tables
 - Transmission connection point info
 - Ancillary Service contract information

- Ancillary Service self-supply balanced schedules data
- Ancillary Service dispatch requirements

5.8.3 Transmission Constrained vs Unconstrained Ancillaries Dispatch

Depending on the characteristics of the particular optimization run, the Ancillary Service dispatch is performed as either:

- transmission constrained, where:
 - Transmission element outages are reflected in the transmission model
 - Transmission line capacity constraints (normal or de-rated) on those lines leaving the connection point bus for a generator are respected during the dispatch, or
- transmission unconstrained, where:
 - transmission line capacity constraints and any transmission element outages are not considered,
 - Facilities flagged as on-line due to transmission congestion (transmission security constraints) are committed off-line in the model
 - Facilities flagged as off-line due to transmission congestion are committed on-line in the model

5.8.4 Fleet Shifting of Self-supplied Ancillary Service Capacity

Loads and generators with incremental reserve obligations schedule their Ancillary Service self-supply obligations from recallable exports and nominated generation fleet resources via balanced schedules. The Ancillary Service Dispatch module will make use of these resources first before dispatching capacity available at contract prices in supplying system ancillary service needs by pricing scheduled self-supply capacity at zero cost. But conditions defined to the Optimization may differ somewhat from those proposed by balanced schedules and this can potentially impact the availability of self-supplied capacity from the specific sources specified in balanced schedules. These differing conditions include:

- Differences in load forecast
- Changes in unit availability or capability
- Cutting of export schedules
- Differences in Load Following requirements that can be used to reduce Operating Reserve requirements

If only capacity from generators specified in balanced schedules is treated as self-supply at zero cost, the SO would be required to purchase capacity at contract prices to replace this lost capacity, with resulting higher ancillary service procurement costs for the market, potential shifting of ancillary service dispatching from one fleet to another and scheduling shortfall costs for the self-supplying loads or generators. But if alternate capacity than that scheduled for self-supply is available from resources in the same fleet, the Optimization can alleviate these problems by shifting self-supply capacity that is no longer available to other resources owned by the same fleet before dispatching for system requirements. For each fleet having self-supply capacity scheduled from its generators this involves:

- Determining how much capacity that was scheduled against recallable exports that are owned by the fleet owner that is no longer available and therefore should be scheduled from fleet generators
- Adjusting operating reserve requirements from fleet generators based on system regulation and load following requirements
- Shifting capacity that was scheduled but not required for one type of operating reserve to the next type of operating reserve to be dispatched
- Once the revised amount of self-supply capacity from a fleet has been determined, dispatch this amount of capacity on fleet generators and price this capacity at zero during system ancillary service dispatch

5.8.5 Ancillary Service Objective Functions and Constraints

The Ancillary Service dispatch consists of the economic selection of available capacity offered by generation facilities for Ancillary Services in order to supply the total system requirement for those Ancillary Services. Ancillary Service capacity that is scheduled on a generator via Balanced Schedules (Ancillary Service self-supply) is available to the SO at zero cost. The remaining capacity is available at the contract price for the generator for the type of Ancillary Service being dispatched.

The ability of a given generation facility to supply Ancillary Services is subject to the following constraints:

- The facility's Ancillary Services contract status
- The facility's commit status (on, off, availability for commitment)
- The facility's ability to supply Ancillary Service capacity of a given type when off-line but available
- The facility's ramping capability from current energy dispatch level
- The facility's Quickstart status
- For Regulation, the facility's Regulation upper and lower limits

5.8.5.1 Glossary - Ancillary Services Optimization

AS_DisReq	-	The system dispatch requirement for an Ancillary Service, indexed by j.
AS_Cost	-	The cost of selection of capacity to meet the Ancillary Service requirements forms the Ancillary Service Dispatch objective function that is to be minimized, and is represented by AS_Cost.
AS_MW_SS	-	MW of generator capacity scheduled as Ancillary Service capacity after self-supply fleet-shifting has been completed that is therefore available to the System Operator at zero cost, indexed by g and j
AS_RedispatchCost_Penalty	-	Once the capacity of a generator is allocated to supply energy, the cost to reallocate that capacity for supply of an Ancillary Service is increased by a penalty factor equal to MaxPDispatched minus P/Q_Pair Prices, and is represented by AS_RedispatchCost_Penalty For capacity that is not allocated to

		supply energy, AS_RedispatchCost_Penalty is set to zero. Indexed by g, j and n.
AS_Redispatch_Penalty -		A small additional penalty on capacity that has already been dispatched for energy in order to favour uncommitted capacity over capacity already committed for energy that has AS_RedispatchCost_Penalty = 0 (marginal generator). Indexed by g, j and n.
AS_QuickStart_Penalty -		A small penalty on capacity from facilities that have quick start capability for the current Ancillary Service that represents the additional cost of enabling the Quick Start mechanism for the facility, thus favouring capacity, other costs being equal, from not-Quick Start facilities over Quick Start facilities. Indexed by g and j.
AS_Activation_Penalty -		Other costs being equal, this cost penalty orders capacity relative to the cost of activation of the capacity, including startup and minimum run costs for off-line capacity. Indexed by g and j.
AS_Ordering_Penalty -		Other costs being equal, this cost penalty orders capacity based on a predefined ordering of generators giving preference to generators having the best performance with respect to supplying Ancillary Service capacity. Indexed by g and j.
AS_MW	-	Generator capacity dispatched to provide a particular Ancillary Service, indexed by g and j.
AS_MW_T	-	Total generator capacity dispatched to provide Ancillary Services, indexed by g.
AS_Max	-	The upper ramping limit on a generator for a particular Ancillary Service based on the energy dispatch level of the generator and the time constant of the Ancillary Service, and is indexed by g and j.
AS_Min	-	The lower ramping limit on a generator for a particular Ancillary Service based on the energy dispatch level of the generator and the time constant of the Ancillary Service, and is indexed by g and j.
AS_Activation_Penalty_Scale	-	A small constant that reduces the generator activation penalty to a size less than all other penalties applied before it.
AS_Ordering_Penalty_Scale	-	A small constant that reduces ordering penalty to a size less than all other penalties applied before it.
AS_Ordering	-	Generator tie-break ordering number, indexed by g.
Energy_MW	-	The Energy Dispatch MW level, indexed by g.
MaxPDispatched	-	The maximum P dispatched during the Energy Dispatch.
REG_Max	-	The upper limit on a generator's Regulation range, indexed by g
REG_Min	-	The lower limit on a generator's Regulation range, indexed by g
StartupCost	-	Generator startup cost, indexed by g.
MRC	-	Generator minimum run cost, indexed by g.

5.8.5.2 Objective Function

For the Ancillary Service objective functions, the cost of selection of capacity from available capacity is minimized, where:

$$AS_MW_T_g = 0$$

For each Ancillary Service j

Minimize the cost AS_Cost_j , where

$$\begin{aligned}
 AS_Cost_j = & \sum_{\{n, g \mid n \in P/Q_PAIRS, g, \text{ where } g \in GENERATORS\}} [(AS_RedispatchCost_Penalty)_{g,j,n} + \\
 & (AS_Redispatch_Penalty)_{g,j,n} + \\
 & (AS_QuickStart_Penalty)_{g,j} + \\
 & (AS_Activation_Penalty)_{g,j} + \\
 & (AS_Ordering_Penalty)_{g,j}] \\
 & \times \text{MIN}(AS_MW_SS_{g,j}, AS_MW_{g,j}) \\
 & + \\
 & \sum [(Ancillary\ Service\ Contract\ Price)_{g,j} + \\
 & (AS_RedispatchCost_Penalty)_{g,j,n} + \\
 & \{n, g \mid n \in P/Q_PAIRS, g, \text{ where } g \in GENERATORS\} \\
 & (AS_Redispatch_Penalty)_{g,j,n} + \\
 & (AS_QuickStart_Penalty)_{g,j} + \\
 & (AS_Activation_Penalty)_{g,j} + \\
 & (AS_Ordering_Penalty)_{g,j}] \\
 & \times \text{MAX}((AS_MW_{g,j} - AS_MW_SS_{g,j}), 0)
 \end{aligned}$$

subject to the constraint that the capacity MW dispatched must equal the dispatch requirement for Ancillary Service j

$$\sum AS_MW_{g,j} = AS_DispReq_j$$

Include dispatched MW for this Ancillary Service for each generator in the generator's total Ancillary Services dispatched total

$$AS_MW_T_g = AS_MW_T_g + \sum AS_MW_{g,j}$$

End For each Ancillary Service j

The first term in the objective function:

$$\begin{aligned} & \sum [(AS_RedispatchCost_Penalty)_{g,j,n} + \\ & \quad \{n, g \mid n \in P/Q_PAIRS \text{ } g, \text{ where } g \in GENERATORS\} \\ & \quad (AS_Redispatch_Penalty)_{g,j,n} + \\ & \quad (AS_QuickStart_Penalty)_{g,j} + \\ & \quad (AS_Activation_Penalty)_{g,j} + \\ & \quad (AS_Ordering_Penalty)_{g,j}] \\ & \quad \times \text{MIN}(AS_MW_SS_{gj}, AS_MW_{g,j}) \end{aligned}$$

represents the cost of capacity made available to the SO at zero cost via Ancillary Service self-supply balanced schedules, but including any cost of energy re-dispatch and other penalties, and limited by the available capacity on the facility.

The second term in the objective function:

$$\begin{aligned} & \sum [(Ancillary \text{ Service Contract Price})_{g,j} + \\ & \quad (AS_RedispatchCost_Penalty)_{g,j,n} + \\ & \quad \{n, g \mid n \in P/Q_PAIRS \text{ } g, \text{ where } g \in GENERATORS\} \\ & \quad (AS_Redispatch_Penalty)_{g,j,n} + \\ & \quad (AS_QuickStart_Penalty)_{g,j} + \\ & \quad (AS_Activation_Penalty)_{g,j} + \end{aligned}$$

$$(\text{AS_Ordering_Penalty})_{g,j}]$$

$$\times \text{MAX} ((\text{AS_MW}_{g,j} - \text{AS_MW_SS}_{g,j}), 0)$$

represents the cost of capacity that has not been made available to the SO under self-supply schedules but rather must be purchased by the SO at Ancillary Service contract prices, but also including any cost of energy re-dispatch and other penalties, and not less than 0 MW.

5.8.5.3 Penalty Terms

The various penalty terms determine the stacking order of Ancillary Service capacity when Ancillary Service contract prices are equal.

5.8.5.3.1 AS_RedispatchCost_Penalty

$\text{AS_RedispatchCost_Penalty}_{g,j,n}$ represents the cost per MW to re-dispatch energy off generator g covered by P/Q pair n that has already been dispatched for energy during Energy Dispatch, during the Ancillary Service Dispatch for Ancillary Service j . That is,

$$\text{AS_RedispatchCost_Penalty}_{g,j,n} = \text{MaxPDispatched} - \text{P/Q Pair } P_{g,n}$$

which estimates the cost per MW of shifting energy from P/Q pair n on generator g to available capacity on some other generator with an estimated cost equaling the cost of the most expensive P/Q pair already dispatched.

For capacity not already allocated for energy, $\text{AS_RedispatchCost_Penalty}_{g,j,n} = 0$.

5.8.5.3.2 AS_Redispatch_Penalty

$\text{AS_Redispatch_Penalty}_{g,j,n}$ is a small additional penalty on capacity that has already been dispatched for energy in order to favour uncommitted capacity over capacity already committed for energy that has $\text{AS_RedispatchCost_Penalty} = 0$ (most expensive energy dispatched). This penalty is a fixed constant that is greater than penalty $\text{AS_QuickStart_Penalty}$ to ensure that capacity from facilities that require Quick Start capability to be enabled is selected before capacity already dispatched for energy.

For capacity not already dispatched for energy, $\text{AS_Redispatch_Penalty}_{g,j,n} = 0$.

5.8.5.3.3 AS_QuickStart_Penalty

$AS_QuickStart_Penalty_{g,j}$ is a small penalty on capacity from facilities that have quick start capability for the current Ancillary Service that represents the additional cost of enabling the Quick Start mechanism for the facility, thus favouring capacity, other costs being equal, from not-Quick Start facilities over that from Quick Start facilities. This penalty is a fixed constant that is less than penalty $AS_Redispatch_Penalty$ to ensure that capacity from facilities that require Quick Start capability to be enabled is selected before capacity already dispatched for energy.

5.8.5.3.4 $AS_ActivationCost_Penalty$

$AS_Activation_Penalty_{g,j}$ is a small penalty that has an impact only when other costs are equal that orders capacity relative to the cost of activation of the capacity, including startup and minimum run costs for off-line capacity. For facilities that are on-line, this cost is defined as the average P/Q cost of energy over the range from its current energy dispatch level to its current ramp rate constrained capacity maximum:

$$AS_Activation_Penalty_{g,j} = \frac{\sum ((P/Q \text{ Pair } Q)_{g,n} - (P/Q \text{ Pair } Q)_{g,n-1}) \times (P/Q \text{ Pair } P)_{g,n}}{(AS_Max_{gj} - Energy_MW_g) \times AS_Activation_Penalty_Scale}$$

for P/Q pair capacity between the energy dispatch level and the facility's current capacity maximum.

For facilities that are off-line but capable of supplying Ancillary Service j, the penalty cost is calculated as the average cost including the facility's minimum run cost and startup cost, and extends from 0 to its current ramp rate constrained capacity maximum:

$$AS_Activation_Penalty_{g,j} = \frac{(StartupCost_g + MRC_g + \sum ((P/Q \text{ Pair } Q)_{g,n} - (P/Q \text{ Pair } Q)_{g,n-1}) \times (P/Q \text{ Pair } P)_{g,n}}{AS_Max_{gj} \times AS_Activation_Penalty_Scale}$$

for P/Q pair capacity between the facility's MRQ and the facility's current capacity maximum.

The scaling factor $AS_Activation_Penalty_Scale$ is a small constant that reduces this penalty to a size less than all other penalties described above.

5.8.5.3.5 $AS_Ordering_Penalty$

$AS_Ordering_Penalty_{g,j}$ is a small penalty that has an impact only when other costs are equal and orders capacity based on a predefined ordering of generators, giving preference to generators having the best performance with respect to supplying Ancillary Service capacity. This penalty is defined as:

$$AS_Ordering_Penalty_g = AS_Ordering_g \times AS_Ordering_Penalty_Scale$$

where $AS_Ordering_Penalty_Scale$ is a small constant that reduces this penalty to a size less than all other penalties described above.

5.8.5.4 Ancillary Service Dispatch Constraints

The Energy Dispatch provides the starting point for the Ancillary Service Dispatch. For the definition of Ancillary Service Dispatch constraints, the Energy Dispatch level for each generator g is represented by:

$$Energy_MW_g = \sum (P/Q_Pair_MW)_{g,n} + MRQ_g$$

5.8.5.4.1 Ancillary Service Contract Status

A generator is eligible to supply a given Ancillary Service only if it has a contract with the SO to supply that Ancillary Service. Otherwise its capacity available for that Ancillary Service is set to zero.

5.8.5.4.2 Facility Commit Status

Facilities with Ancillary Service contracts can be categorized as follows with respect to their commitment status:

- Committed on for dispatch hour: Capacity from committed generator is available for selection
- Committed off and not capable of starting within 30 minutes: Capacity from generator is not available for selection
- Committed off but capable of starting within 30 minutes (such as combustion turbines): Capacity is available for selection for 30 minute non-spinning Operating Reserve only

- Committed off but capable of starting within 10 minutes (such as combustion turbines with quick start capability): Capacity is available for selection for either 10 or 30 minute non-spinning Operating Reserve

Commit Status	Can Start in 30 Minutes	Can Start in 10 minutes	Capacity Available (if contract)				
			REG	LF	10S	10N	30N
On	N/A	N/A	Yes	Yes	Yes	Yes	Yes
Off	No	No	No	No	No	No	No
Off	Yes	No	No	No	No	No	Yes
Off	Yes	Yes	No	No	No	Yes	Yes

5.8.5.4.3 Generator Rated Maximum

The capacity available for selection plus the sum of the energy dispatched and capacity already selected for Ancillary Services on a generator is limited by the generator's rated maximum

$$\text{Energy_MW}_g + \text{AS_MW_T}_g + \text{AS_MW}_{g,j} \leq \text{Gen_Max}_g$$

5.8.5.4.4 Unit Outages/Derations

Ancillary Service capacity from generators on outage is not available for selection.

For a partial outage, or deration, the capacity available for selection plus the sum of the energy dispatched and capacity already selected for Ancillary Services on a generator is limited by its derated maximum.

$$\text{Energy_MW}_g + \text{AS_MW_T}_g + \text{AS_MW}_{g,j} \leq \text{D_Gen_Max}_g$$

5.8.5.4.5 Transmission Congestion

For optimization runs that are transmission constrained, the capacity available for selection plus the sum of the energy dispatched and capacity already selected for Ancillary Services on a generator is subjected to analysis in order to determine whether any transmission constraints on lines leaving the transmission model connection point bus would limit the selection of MW from the generator.

$$\text{Energy_MW}_g + \text{AS_MW_T}_g + \text{AS_MW}_{g,j} \leq \text{T_Gen_Max}_g$$

For optimization runs that are not transmission constrained, T_Gen_Max is set to large (non-constraining).

5.8.5.4.6 Facility Maximum P/Q Pair Q

The maximum P/Q pair Q value represents the maximum MW offered to the Market by the facility and therefore limits the capacity that is available from the facility to supply Ancillary Services.

$$\text{Energy_MW}_g + \text{AS_MW_T}_g + \text{AS_MW}_{g,j} \leq \text{Q_Gen_Max}_g$$

5.8.5.4.7 Facility Ramping Capability

The available capability for a given ancillary service is constrained by the ramping capability of the facility from its current energy dispatch level over the time constant characteristic of the Ancillary Service.

$$\text{Energy_MW}_g + \text{AS_MW}_{g,j} \leq \text{AS_Max}_{g,j}$$

For Regulation, which requires capacity in both the up and down directions, the available capability in the downward direction is constrained by the downward ramping capability of the facility from its current energy dispatch level over the time constant characteristic for Regulation (10 minutes).

$$\text{Energy_MW}_g - \text{AS_MW}_{g,j} \geq \text{AS_Min}_{g,j}$$

5.8.5.4.8 Regulation Range Limits

Regulation Ancillary Service requires regulation capacity in both the up and down directions from the energy dispatch level, and as well, some generation facilities are only capable of supplying Regulation service within a subset of their normal energy operating range. Therefore, where $j = j_{\text{REG}}$

$$\text{Energy_MW}_g + \text{AS_MW}_{g,j} \leq \text{REG_Max}_{g,j}$$

$$\text{Energy_MW}_g - \text{AS_MW}_{g,j} \geq \text{REG_Min}_{g,j}$$

Part 6 Optimization Outputs

6.1 Provisional and Final Day Ahead Commitment Schedules

6.1.1 The Provisional and Final Day Ahead Commitment Schedules are hourly schedules for each Generation Facility for the next day's supply of Energy and Ancillary Services.

6.2 Final Hourly Commitment Schedule

6.2.1 The Final Hourly Commitment Schedule is a commitment schedule for each Generation Facility for the next hour's supply of Energy and Ancillary Services. This schedule forms the basis for the creation of Dispatch Instructions, which are issued as per MP-19.

6.3 Final Hourly Marginal Cost

6.3.1 The Final Hourly Marginal Cost (FHMC) for each dispatch hour is determined by the FHCS optimization run as defined in the Market Rules and is an important input to the market settlement process.

Part 7 Flow Chart

None.

Appendix C

New Brunswick Electricity Market Rules Chapter 6

New Brunswick System Operator

New Brunswick Electricity Market Rules

**Version 3.0
September 26, 2007**

TABLE OF CONTENTS

CHAPTER 6 - OPERATIONAL REQUIREMENTS	263
6.0 Introduction and Coming Into Force	263
6.1 Scheduling and Dispatch Objectives, Review and Audit	265
6.2 Ancillary Service Self-Supply and Nomination.....	267
6.3 Short-term Assessment and System Status Reporting.....	274
6.4 Capacity Resource Obligation and Cold Condition.....	275
6.5 Form and Effect of Balanced Schedules and Dispatch Data	276
6.5A Access to Balanced Schedule Data.....	279
6.5B Designated Scheduling Agents	280
6.6 Day Ahead Forecast, Provisional Balanced Schedules and Provisional Dispatch Data	281
6.7 Initial Assessment and Control Actions	284
6.8 Provisional Commitment Schedule.....	288
6.9 Day Ahead Final Input and Commitment Schedule	289
6.10 Changes and Deviations	292
6.11 Two Hour Review and Control Actions	298
6.12 Generator Synchronisation, De-synchronisation and Switching Devices.....	300
6.13 Hour Ahead Dispatch	300
6.14 Real Time Operation	303
6.15 Forced Outages (including forced de-ratings)	304
6.16 Ancillary Services	306
6.17 Emergency and High Risk Operating States and Emergency Energy	308
6.18 Publication of System Information	309
Appendix 6A -Control Actions	311

CHAPTER 6 - OPERATIONAL REQUIREMENTS

6.0 Introduction

6.0.1 This Chapter sets forth provisions relating to:

- a) the manner in which the SO will schedule energy transactions, dispatch resources and supply Ancillary Services;
- b) the obligations of the SO in respect of short-term forecasting and adequacy assessments;
- c) the manner in which Market Participants must submit Balanced Schedules and Dispatch Data;
- d) Control Actions that may be taken by the SO;
- e) the manner in which Generation Facilities may synchronize to or de-synchronize from the SO-controlled Grid;
- f) the responsibilities of the SO in real time;
- g) Forced Outages; and
- h) Emergency Operating States and High Risk Operating States.

6.0.2 A Generation Facility and a Joint Facility shall comply in all respects with:

- a) all obligations imposed by this Chapter on Load Facilities at all times at which the Generation Facility or the Joint Facility is withdrawing or is expected to withdraw, as the case may be, electricity from the SO-controlled Grid; and

- b) the obligations imposed by this Chapter on Generation Facilities at all times at which the Generation Facility or the Joint Facility is injecting or is expected to inject, as the case may be, electricity into the SO-controlled Grid,

and each Market Participant for a Generation Facility or a Joint Facility shall comply with all corresponding obligations imposed on Market Participants for Generation Facilities and Load Facilities.

6.0.3 The SO shall treat a Generation Facility or a Joint Facility as:

- a) a Load Facility under this Chapter in respect of all times at which the Generation Facility or the Joint Facility is withdrawing or is expected to withdraw, as the case may be, electricity from the SO-controlled Grid; and
- b) a Generation Facility under this Chapter in respect of all times at which the Generation Facility or the Joint Facility is injecting or is expected to inject, as the case may be, electricity into the SO-controlled Grid,

and shall treat the Market Participant for a Generation Facility or a Joint Facility accordingly.

6.0.3A Without limiting the generality of sections 6.0.2 and 6.0.3, a Joint Facility may be the subject of an Interruptible Load contract referred to in section 5.4.6, and a Joint Facility and the Market Participant for a Joint Facility shall be treated accordingly.

6.0.4 Sections 6.2 and 6.4 are not applicable to Bid-Based Demand Response, notwithstanding the obligations contained in this chapter that apply to the Market Participant for the Facility with which the Bid-Based Demand Response is associated.

6.1 Scheduling and Dispatch Objectives, Review and Audit

6.1.1 The SO shall, in scheduling energy transactions and Ancillary Services, pursue the following objectives, in descending order of priority:

- a) maintaining Reliability of the Integrated Electricity System, including with respect to any Zone, in accordance with the requirements of applicable Standards Authorities, and undertaking congestion management of Interconnection transactions in accordance with Interconnection Agreements;
- b) completion of firm energy transactions scheduled by Market Participants under Bilateral Contracts, subject to the economic dispatch of resources referred to in section 6.1.1(e);
- c) minimizing energy transactions other than those scheduled under Bilateral Contracts or as Ancillary Services, such as purchasing Emergency Energy and inadvertent exchange;
- d) completion of non-firm energy transactions scheduled by Market Participants under Bilateral Contracts and completion of Interruptible Load transactions; and
- e) the economical dispatch of resources available to the SO and the SO-controlled Grid in accordance with section 6.1.2.

6.1.2 In pursuing the objective described in section 6.1.1(e), the SO shall:

- a) have regard for the capabilities of each Facility;
- b) have regard for the Balanced Schedules submitted by Market Participants;
- c) have regard for any daily energy limits on Generation Facilities contained in Dispatch Data;

- d) have regard to any stream flow and meteorological data available to it; and
- e) schedule Ancillary Services and reschedule energy dispatch as necessary to:
 - i. acquire the required Ancillary Services;
 - ii. mitigate the effect of Transmission constraints on the SO-controlled Grid, other than at any Interconnection;
 - iii. accommodate forecast variances;
 - iv. accommodate schedule variances; and
 - v. respond to contingency events,

all in accordance with Ancillary Services contracts, including those referred to in section 6.2, and with the Dispatch Data submitted by Market Participants for Generation Facilities.

6.1.3 The SO shall ensure that its internal procedures and systems are designed to pursue the objectives described in section 6.1.1 in a consistent and auditable manner.

6.1.4 The SO shall ensure that its internal procedures and systems relating to the functions and responsibilities of the SO under this Chapter are subject to an independent design and performance review or audit within five years of the Systems Implementation Date and thereafter no less than every five years. The results of each such review or audit, excluding any Confidential Information or information the disclosure of which could jeopardise the integrity of the Integrated Electricity System, shall be Published by the SO. The process will commence within one year of the Systems Implementation Date and intermediate results of that process will be Published annually by the SO, excluding any Confidential Information or information the disclosure of which could jeopardise the integrity of the Integrated Electricity System.

6.1.5 The SO shall ensure that an independent design and performance review and audit of the SO's internal procedures and systems relating to the functions and responsibilities of the SO under this Chapter is conducted at the request of any Market Participant. The costs of such review and audit shall be borne by the requesting Market Participant unless the review and audit reveals material deficiencies that significantly affect the commercial interests of any Market Participant in a manner not otherwise contemplated in the Market Rules or any applicable agreement between the SO and that Market Participant.

6.2 Ancillary Service Self-Supply and Nomination

6.2.1 Subject to section 6.2.2, where one or more transactions create exposure to a first or second contingency in excess of 500 MW, each Market Participant responsible for any such transaction shall provide or pay for its proportionate share of the incremental Operating Reserve beyond that required by the first or second contingency event, respectively, of up to 500 MW. The provision or self-supply of such incremental Operating Reserve shall be effected in accordance with this section 6.2. The payment for such incremental Operating Reserve shall be allocated and effected in accordance with section 7.9.9. For the purposes of this section 6.2.1 and of section 6.2.2, the terms "first contingency", "first contingency event", "second contingency" and "second contingency event" shall be interpreted in the same manner as the term "first contingency loss" and "second contingency loss" as defined by the Northeast Power Coordinating Council.

6.2.2 In the event that exposure to a first or second contingency in excess of 500 MW arises due to an Outage or failure of a part of the bulk transfer capability of the SO-controlled Grid, the SO shall procure the incremental Operating Reserve requirement and recover the costs incurred for the procurement of such incremental Operating Reserve up to 500 MW in accordance with Chapter 7 other than section 7.9.9.

6.2.3 The self-supply of 10-minute non-spinning Operating Reserve and 30-minute Operating Reserve under section 6.2.1 may be effected by the Market Participant

- demonstrating to the satisfaction of the SO that the supply to the Load within New Brunswick or the export transaction is interruptible within ten or thirty minutes, respectively, at the call of the SO in the event of failure of the Generation Facility or import transaction. In the event that Load is interrupted under an IL Contract, or is scheduled by the SO as Operating Reserve, or is nominated or scheduled by any Market Participant as self-supplied Operating Reserve, then it shall not be eligible as self-supplied incremental Operating Reserve under this section. Any self-supply of Operating Reserve shall otherwise be satisfied by the conclusion of an Ancillary Service contract, and sections 6.2.4 to 6.2.16 shall apply with such modifications as the context may require.
- 6.2.4 A Market Participant in New Brunswick within the class referred to in section 2.2.1(b) that uses Network Integration Service and that wishes to self-supply Ancillary Services shall apply to the SO for approval to do so. Such application shall specify the Ancillary Services proposed for self-supply and the means proposed for such self-supply, including the identity of any Facility that will be used to provide the Ancillary Services. Such application may specify an intention to self-supply only a part of a particular Ancillary Service, expressed either as the maximum capacity of the Facility that will be used to provide the Ancillary Service or as a percentage of the Market Participant's total obligation for that Ancillary Service. Such application shall be submitted at least one month in advance of the first occasion on which any applicable facility is proposed to be used by the Market Participant for the self-supply of such Ancillary Service. Such application shall be for a period of at least one year. The Market Participant shall nominate the particular facilities to be used for self-supply in each particular month, at least five Business Days in advance of the start of the applicable month.
- 6.2.5 A Market Participant in New Brunswick within the class referred to in section 2.2.1(b) that uses Point-to-Point Service and that wishes to self-supply Ancillary Services shall apply to the SO for approval to do so. Such application shall specify the Ancillary Services proposed for self-supply and the means proposed for such self-supply, including the identity of any Facility that will be used to

provide the Ancillary Services. Such application may specify an intention to self-supply only a part of a particular Ancillary Service, expressed either as the maximum capacity of the Facility that will be used to provide the Ancillary Service or as a percentage of the Market Participant's total obligation for that Ancillary Service. Such application shall be submitted at least one month in advance of the first occasion on which any applicable Facility is proposed to be used by the Market Participant for the self-supply of such Ancillary Services and at least five Business Days in advance of the start of each other applicable month.

6.2.6 Upon receipt of an application under section 6.2.4 or 6.2.5, the SO shall review the self-supply proposal. If the proposal satisfies the SO's criteria for the supply of the applicable Ancillary Services and would not result in a violation of section 6.2.18, the SO and the Market Participant for a Facility that will be used to provide the Ancillary Services shall enter into an Ancillary Services contract in the form set forth in Appendix 5A, except that such contract shall provide:

- a) for a term that is at least co-extensive with the commitment by the applicable Market Participant to self supply such Ancillary Services;
- b) that there shall be no payment from the SO for such Ancillary Services;
- c) that the Balanced Schedules in respect of energy from the Facility shall be limited to the output that does not conflict with the provision of the Ancillary Services, and that the Facility will be operated at all times to provide the Ancillary Services except when otherwise dispatched or activated by the SO;
- d) where the contract is for the provision of 10-minute spinning Operating Reserve, that the Facility shall be synchronized at all times that it is required to provide such Operating Reserve also without payment from the SO; and
- e) that each applicable Ancillary Service shall be provided under such contract before being provided under any other contract for the provision

of the same Ancillary Service by the same Facility where that other contract provides for payment from the SO for the Ancillary Service.

- 6.2.7 Where the SO enters into a contract under section 6.2.6, the Market Participant that is thus self-supplying Ancillary Services shall, for each month in the term of the contract and to the extent determined by the SO under section 6.2.16, be excused from the payment of charges to the SO in respect of the Ancillary Services covered by the contract except in respect of any day on which an applicable Facility is unavailable or unable to provide the Ancillary Service for any reason other than a Transmission constraint within New Brunswick.
- 6.2.8 Where a self-supply proposal does not satisfy the criteria referred to in section 6.2.6 or the SO is unable to enter into the contract referred to in that section with the Market Participant for the applicable Facility, the Market Participant that applied to the SO for approval to self-supply Ancillary Services shall purchase Ancillary Services from the SO in accordance with the Transmission Tariff and the Market Rules other than this section 6.2.
- 6.2.9 An External Load Participant shall, promptly following the Market Commencement Date and thereafter as part of its regular Interconnection Agreement renewal process, propose to the SO which, if any, Ancillary Services it wishes to self-supply and which it wishes to purchase from the SO. Such proposal may specify an intention to self-supply only a part of a particular Ancillary Service, expressed either as the maximum capacity of the Generation Facility that will be used to provide the Ancillary Service or as a percentage of the Market Participant's total obligation for that Ancillary Service. Where the External Load Participant wishes to self-supply an Ancillary Service, it shall identify each Generation Facility that will provide such Ancillary Service. The External Load Participant shall ensure that no other use of such Generation Facility conflicts with the provision by it of such Ancillary Service.
- 6.2.10 Upon receipt of a proposal under section 6.2.9, the SO shall review the self-supply proposal. If the proposal satisfies the SO's criteria for the supply of the applicable Ancillary Services and would not result in a violation of section 6.2.18,

the SO and the Market Participant for the Generation Facility that will be used to provide the Ancillary Services shall enter into an Ancillary Services contract in the form set forth in Appendix 5A, except that:

- a) such contract shall provide that there shall be no payment from the SO for such Ancillary Services;
- b) if agreed between the External Load Participant and the SO, such contract may provide for the ability of the External Load Participant to nominate, on a monthly basis, those Ancillary Services that will be provided under the contract and those that will be purchased by the External Load Participant from the SO, provided that such nomination is notified to the SO at least five Business Days prior to the start of each month;
- c) such contract shall provide that the Balanced Schedules in respect of energy from the Facility shall be limited to the output that does not conflict with the provision of the Ancillary Services, and that the Facility will be operated at all times to provide the Ancillary Services except when otherwise dispatched or activated by the SO;
- d) such contract shall provide that each applicable Ancillary Service shall be provided under such contract before being provided under any other contract for the provision of the same Ancillary Service by the same Generation Facility where that other contract provides for payment from the SO for the Ancillary Service; and
- e) such contract shall be for a term that is co-extensive with the term of the Interconnection Agreement between the External Load Participant and the SO, exclusive of any renewal term.

6.2.11 Subject to section 6.2.12, where the SO enters into a contract under section 6.2.10, the External Load Participant to which the contract relates shall, for each month in the term of the contract and to the extent determined by the SO under

- section 6.2.16, be excused from the payment of charges to the SO in respect of the Ancillary Services covered by the contract except in respect of any day on which the Generation Facility is unavailable or unable to provide the Ancillary Service for any reason other than a Transmission constraint within New Brunswick.
- 6.2.12 Section 6.2.11 shall not excuse payment of charges to the SO in respect of Ancillary Services for which a nomination has been notified to the SO under section 6.2.10(b) indicating that the External Load Participant will purchase such Ancillary Services from the SO, nor in respect of Ancillary Services obligations determined on the basis of actual charge determinant quantities to be in excess of the quantity provided under the contract.
- 6.2.13 Where a self-supply proposal does not satisfy the criteria referred to in section 6.2.10 or the SO is unable to enter into the contract referred to in that section with the Market Participant for the applicable Generation Facility, the External Load Participant shall purchase Ancillary Services from the SO in accordance with the Transmission Tariff and the Market Rules other than this section 6.2.
- 6.2.14 A Market Participant that reserves Point-to-Point Service in respect of an export transaction or a Wheeling transaction shall, if the load thus served is within the Maritime Control Area, nominate to the SO those Ancillary Services that it will be purchasing from the SO in each month for which Point-to-Point Service has been reserved. Such nomination shall be notified to the SO at least five Business Days prior to the start of each such month.
- 6.2.15 A Market Participant that is self-supplying Operating Reserve other than incremental Operating Reserve under section 6.2.1 may, subject to the applicable Market Procedure, satisfy its self-supply obligation by means of the submission of a Balanced Schedule for an export from the Maritime Control Area that is recallable within the relevant time frames.

6.2.16 For the purposes of sections 6.2.7 and 6.2.11, the charge determinant quantity of a self-supplied Ancillary Service for a Market Participant shall be determined each month by the SO for settlement purposes as follows:

- a) the SO shall determine the forecast total peak requirement for the Ancillary Service for the month, excluding any Ancillary Service that is to be provided or self-supplied under section 6.2.1;
- b) the SO shall determine the fraction "F" of the forecast total peak requirement referred to in section 6.2.16(a) that is forecast to be fulfilled by a Facility under the contract referred to in section 6.2.6 or 6.2.10;
- c) the SO shall determine the forecast total "T" for the month of the charge determinants applicable to the Ancillary Service, including in respect of Market Participants who self-supply such Ancillary Service;
- d) the SO shall determine the maximum quantity "M" of load on which the Market Participant is excused from the payment of charges for Ancillary Services for the month as $F \times T$; and
- e) the Market Participant's charge determinant quantity for the month shall be reduced by the lesser of:
 - i. M; and
 - ii. the product of the Market Participant's charge determinant quantity and that percentage (which shall not be more than 100 percent) of the charge determinant quantity for the Ancillary Service that is to be self-supplied.

6.2.17 The SO Board may, following consultation with the Market Advisory Committee, determine and Publish, and from time to time amend and re-Publish, the following values for any given Ancillary Service:

- a) "QLim", which shall be an absolute quantity, expressed in MW; and

- b) "PLim", which shall be a percentage.

6.2.18 Subject to section 6.2.19, where "QLim" and "PLim" have been Published for an Ancillary Service under section 6.2.17, the maximum amount of that Ancillary Service that can be self-supplied by a Market Participant at any given time shall be the greater of:

- a) "QLim"; and
- b) "PLim" multiplied by the Market Participant's total obligation for that Ancillary Service.

6.2.19 Section 6.2.18 does not apply to the self-supply of incremental Operating Reserve under section 6.2.1.

6.3 Short-term Assessment and System Status Reporting

6.3.1 The SO shall Publish on a weekly basis a forecast of:

- a) New Brunswick Demand, as required by section 5.3.1(b), and the requirements for Ancillary Services for New Brunswick;
 - b) all Transmission interface limits in New Brunswick; and
 - c) the Available Transfer Capacity on all Interconnections,
- for the next 28 days, by day and by hour.

6.3.2 The SO shall Publish by 09:00 on each Business Day a forecast of:

- a) New Brunswick Demand, as required by section 5.3.1(a), and the requirements for Ancillary Services for New Brunswick;
 - b) all Transmission interface limits within New Brunswick; and
 - c) the Available Transfer Capacity on all Interconnections,
- for the next five days, by hour.

6.3.3 In assessing and scheduling Ancillary Services, the SO shall adjust New Brunswick requirements to take into account any agreements with other Control Area Operators or the operators of neighbouring transmission systems regarding the shared scheduling of Operating Reserve, subject to continued compliance by the SO with the standards established by applicable Standards Authorities.

6.4 Capacity Resource Obligation and Cold Condition

6.4.1 The Market Participant for each Capacity Resource that is not on a Planned Outage approved by the SO under Chapter 5 or a Forced Outage shall, unless the Facility is otherwise approved by the SO under section 6.4.3 to be in a Cold Condition:

- a) if the Capacity Resource is a Generation Facility within New Brunswick or an External Dispatchable Facility, submit Dispatch Data and ensure that the Capacity Resource is available to synchronize to the SO-controlled Grid and ramp promptly to supply its full Committed Capacity with no more than 12 hours advance notice; or
- b) if the Capacity Resource is a Generation Facility located outside New Brunswick other than an External Dispatchable Facility, ensure that the Capacity Resource is available for scheduling of a firm import to New Brunswick with no more than 12 hours advance notice and otherwise as provided for in this Chapter.

6.4.1A Any failure to be available as required by section 6.4.1 shall be subject to a penalty of up to twice the per annum long run marginal cost of gas turbine peaking plant capacity for the quantity of the resulting shortfall. Notwithstanding section 3.4.3(c), in no event shall such penalty be, for any occurrence of a failure, less than ten percent of the maximum penalty that may be imposed by the SO. Where the SO is required as a result of the failure to curtail firm load, the SO shall impose the maximum penalty. In all other cases, in determining the amount of the penalty, the SO shall have regard to the diligence demonstrated by the

Market Participant in attempting to rectify the failure and to the other criteria referred to in section 3.4.4.

6.4.2 The Market Participant for a Capacity Resource may, at any time within five days prior to a Dispatch Day, request approval of the SO to be in a Cold Condition on that Dispatch Day.

6.4.3 The SO shall assess all such requests in the order in which they were received, and may grant approval for one or more Capacity Resources to be in a Cold Condition on a given Dispatch Day to the extent that such approval will not have an adverse impact on Adequacy of the Integrated Electricity System or of any Zone.

6.5 Form and Effect of Balanced Schedules and Dispatch Data

6.5.1 A Balanced Schedule shall be submitted in the manner and form required by the applicable Market Procedure and shall comply with the applicable requirements of this Chapter. The SO may reject any Balanced Schedule that does not meet such requirements. The Market Procedure shall:

- a) include provisions respecting the manner in which a Balanced Schedule shall treat transmission losses and self-supplied Ancillary Services to be provided to the SO;
- b) allow, by means of the use of Virtual Delivery Points, for the Market Participant to submit a Balanced Schedule on a consolidated basis for more than one Load Facility using Network Integration Service;
- c) include provisions respecting the circumstances in which energy flows under different categories of Balanced Schedules in respect of import or export transactions may be adjusted within the Dispatch Hour; and
- d) include provisions:

- i. requiring a Market Participant that wishes to export electricity from Canada to submit to the SO details of the export licence or permit issued by the National Energy Board authorizing the export; and
- ii. prohibiting the SO from accepting a Balanced Schedule in respect of an export of electricity from Canada unless the details referred to in section 6.5.1(d)(i) have been provided to it in respect of the export.

6.5.2 Dispatch Data shall be submitted in the manner and form required by the applicable Market Procedure and shall comply with the applicable requirements of this Chapter. The SO may reject any Dispatch Data that does not meet all such requirements.

6.5.3 The Market Procedure referred to in section 6.5.2 shall make provision for the following:

- a) Dispatch Data shall include start-up costs, which shall be a genuine pre-estimate of the actual incremental operating costs for each Generation Facility to start up, synchronize, come up to its minimum operating level and shut down again, but shall exclude any costs:
 - i. associated with energy production while ramping up to the Generation Facility's Minimum Run Quantity, with operation at the Generation Facility's minimum operating level or with ramping down from the Generation Facility's Minimum Run Quantity; or
 - ii. that are reasonably expected to be otherwise recoverable by the Market Participant under the Market Rules;
- b) Dispatch Data shall include a Minimum Run Quantity or "MRQ", a Minimum Run Time or "MRT" and Minimum Run Costs or "MRC", where the Minimum Run Quantity is the lowest level of output for stable operation of the Generation Facility, the Minimum Run Time is the minimum duration, in hours, over which the Generation Facility should

operate at no less than its Minimum Run Quantity in order to avoid harm to the Generation Facility, and the Minimum Run Costs are the hourly costs of operating the Generation Facility at its Minimum Run Quantity;

- c) Dispatch Data shall comply with section 6.5.4 and may include up to 10 price-quantity pairs ("P/Q Pairs"). Each P/Q Pair shall comprise:
 - i. "Q(n)", an absolute integer value of total energy output; and
 - ii. "P(n)", a price in dollars and cents per MWh to be paid by or to the SO to or by the Market Participant for any energy re-dispatched from the Generation Facility in the range Q(n-1) to Q(n), where the energy re-dispatched from the Generation Facility shall be the difference between the energy dispatched and the total of the quantities set forth in the applicable Balanced Schedules for that Generation Facility; and
- a) Dispatch Data for a hydraulic Generation Facility shall also comply with the following:
 - i. P(1) shall not exceed 0; and
 - ii. Q(1) shall not be less than the generation output corresponding to the minimum hourly flow required by Applicable Law pertaining to the environment.

6.5.4 Dispatch Data shall be structured in such a way that:

- a) the Minimum Run Quantity shall be treated as Q(0);
- b) P(1) shall be the re-dispatch price for each MWh of energy re-dispatched in the range Q(0) to Q(1);
- c) Q(n) shall always be greater than Q(n-1), except that Q(1) may be equal to the Minimum Run Quantity, Q(0), unless precluded by the application of another section;

- d) $P(n)$ shall always be greater than $P(n-1)$;
 - e) each value of Q shall be the quantity of energy in MWh over each hour;
 - f) the highest $Q(n)$ shall not exceed the maximum net hourly output of the Generation Facility as determined on the basis of the Generation Facility's rated net capacity;
 - g) $P(1)$ shall never be less than $-\$2,000.00$; and
 - h) $P(n_{max})$ shall never be greater than $\$2,000.00$.
- 6.5.5 In submitting Dispatch Data for a Generation Facility, the Market Participant shall specify a separate set of P/Q Pairs for each hour of the Dispatch Day. Dispatch Data for all Generation Facilities for any Dispatch Day that has been accepted by the SO shall remain in effect until superseded in accordance with section 6.9 or 6.10 or withdrawn by the Market Participant.
- 6.5.6 A Market Participant may submit Dispatch Data for each of up to five days ahead, and a Balanced Schedule for each of up to forty-five days ahead.
- 6.5.7 In the event that the SO does not accept any Dispatch Data for a Facility in respect of a given Dispatch Day, the most recent Dispatch Data applicable to the Facility for the previous Dispatch Day shall apply.
- 6.5.8 Dispatch Data for Bid-Based Demand Response shall be submitted in compliance with the Market Procedure referred to in section 6.5.2, subject to any additional requirements, or exemptions from requirements, noted in the Market Procedure for Bid-Based Demand Response. Such submissions shall be made no earlier than sixty days from the SO's accreditation of the first Market Participant for Bid-Based Demand Response without the express consent of the SO which shall only be granted upon completion of the required systems.

6.5A Access to Balanced Schedule Data

6.5A.1 The SO shall ensure that the Market Participant for a Generation Facility or a Joint Facility has, at all times, access to the following information in respect of each Balanced Schedule that has been accepted by the SO, including a revised Balanced Schedule, and that pertains to the scheduling of the output of that Generation Facility or Joint Facility:

- a) the amount of energy and of any Ancillary Service scheduled from that Generation Facility or Joint Facility under the Balanced Schedule;
- b) the identity of the Market Participant that submitted the Balanced Schedule;
- c) the unique identifier for the Balanced Schedule required under the Market Procedure referred to in section 6.5.1; and
- d) such other data pertaining to the identification and status of the Balanced Schedule as may be specified in the Market Procedure referred to in section 6.5.1.

6.5A.2 The SO shall ensure that the provision of access under section 6.5A.1 is effected in such a manner as to preclude a Market Participant from having access to any Balanced Schedule information that pertains to any Facility for which it is not the Market Participant.

6.5B Designated Scheduling Agents

6.5B.1 A Market Participant may designate a person authorized to act on the Market Participant's behalf in respect of all matters relating to Balanced Schedules. The SO shall recognize such person as the Market Participant's Designated Scheduling Agent provided that the SO receives notice of the designation no less than 5 Business Days and no more than 20 Business Days before the date on which the designation is to take effect.

6.5B.2 A Market Participant may withdraw the designation of a Designated Scheduling Agent. The SO shall not give effect to such withdrawal unless it receives

notification of the withdrawal no less than 5 Business Days and no more than 20 Business Days before the date on which the withdrawal is to take effect.

6.5B.3 While the designation of a Designated Scheduling Agent is in effect, the SO shall use reasonable efforts to communicate with a Market Participant's Designated Scheduling Agent in respect of all matters relating to the Market Participant's Balanced Schedules, and any such communication shall be deemed to be communication with the Market Participant. The SO reserves the right to communicate directly with the Market Participant in respect of the Market Participant's Balanced Schedules, and any such communication shall be effective notwithstanding that a Designated Scheduling Agent has been appointed by the Market Participant.

6.5B.4 The act or omission of a Market Participant's Designated Scheduling Agent shall be deemed to be the act or omission of the Market Participant. As between the SO and the Market Participant, the Market Participant shall be bound by and fully liable for all acts or omissions of its Designated Scheduling Agent and shall remain solely responsible and liable to the SO for the due performance of its obligations under the Market Rules.

6.5B.5 Nothing in this section 6.5 shall be construed as limiting the generality of section 1.7.3.

6.6 Day Ahead Forecast, Provisional Balanced Schedules and Provisional Dispatch Data

6.6.1 The SO shall, by 09:00 on each Day Ahead, Publish in respect of each hour of the corresponding Dispatch Day:

- a) an updated forecast of New Brunswick energy Demand;
- b) an updated forecast of the requirements for each Ancillary Service for New Brunswick;
- c) updated forecasts of aggregate Outages of:

i. Capacity Resources; and

ii. other Generation Facilities;

including the generation portion of Load Facilities referred to in sections 5.5.0 and 5.7.0; and

d) the updated status of Transmission limits on the SO-controlled Grid and of Outages to Transmission facilities.

6.6.2 A Market Participant may only submit a Balanced Schedule in respect of an energy transaction if the Market Participant is not precluded from access to the SO-controlled Grid by application of the reciprocity provisions of the Transmission Tariff contemplated in section 2.1.4, and is either:

a) the Transmission customer for Point-to-Point Service;

b) the Market Participant for the sink Delivery Point or Virtual Delivery Point for Network Integration Service; or

c) the Market Participant responsible for the provision or self-supply of incremental Operating Reserve under section 6.2.1.

A Market Participant submitting a Balanced Schedule shall ensure that in no event is a Balanced Schedule submitted twice for the same energy transaction, except where one clearly supersedes the other.

6.6.3 A Market Participant wishing to have the SO schedule an energy transaction on a Dispatch Day shall, except as otherwise noted in section 6.7.3(c), by 11:00 on the corresponding Day Ahead, submit to the SO a Provisional Balanced Schedule comprising:

a) a balanced hourly schedule of energy flows utilizing firm Point-to-Point Service, specifying injection and withdrawal Delivery Points, including those at Interconnections, and the quantities of energy to be injected and

withdrawn at each, to take account of Transmission losses in accordance with the Transmission Tariff;

- b) a balanced hourly schedule of energy flows utilizing Network Integration Service, specifying injection and withdrawal Delivery Points or Virtual Delivery Points, including those at Interconnections where not prohibited by the Transmission Tariff, and the quantities of energy to be injected at each, taking account of Transmission losses in accordance with the Transmission Tariff; and
- c) hourly schedules of self-supplied Ancillary Services, by Facility.

Quantities of energy to be injected or withdrawn, contained in a schedule referred to in section 6.6.3 shall be expressed in integer MWh/hr. Ancillary Services to be provided to the SO as self-supplied Ancillary Services contained in a schedule referred to in section 6.6.3 shall be expressed in tenths of a MWh/hr.

6.6.4 A Market Participant for a Generation Facility that is required under section 6.4.1 to submit Dispatch Data, that is scheduled to inject energy on a Dispatch Day under a Provisional Balanced Schedule submitted by another Market Participant, or that has contracted to provide an Ancillary Service under an Ancillary Services contract, including an Ancillary Services contract referred to in section 6.2, on a Dispatch Day, shall, unless the Generation Facility is on a Planned Outage approved by the SO under Chapter 5 or a Forced Outage, by 11:00 on the corresponding Day Ahead submit to the SO Provisional Dispatch Data in accordance with the applicable requirements of section 6.5.

6.6.5 The Provisional Dispatch Data to be provided in respect of a Capacity Resource that is proposed to operate for the provision of energy or an Ancillary Service shall meet the applicable requirements described in section 6.5, and shall be for the full Committed Capacity of that Capacity Resource unless the Capacity Resource is on a Planned Outage approved by the SO under Chapter 5, is on a Forced Outage, is in a Cold Condition with the approval of the SO given under section 6.4 or has a reduced output capability due to a Force Majeure Event,

ambient conditions or, in the case of a hydraulic Generation Facility, a shortage of water.

6.6.6 A Market Participant that has contracted to provide Ancillary Services from a Load Facility but is not the Market Participant for that Facility, including an Ancillary Services contract referred to in section 6.2, on a Dispatch Day, shall, unless the Facility is on a Planned Outage approved by the SO under Chapter 5 or a Forced Outage, by 11:00 on the corresponding Day Ahead submit to the SO Provisional Dispatch Data in accordance with the applicable requirements of section 6.5.

6.6.7 A Market Participant for an External Dispatchable Facility that is not a Capacity Resource, and a Market Participant for Bid-Based Demand Response, may submit Dispatch Data in accordance with the applicable requirements of section 6.5.

6.7 Initial Assessment and Control Actions

6.7.1 By 12:00 on each Day Ahead, the SO shall complete an initial assessment of the Provisional Balanced Schedules and Provisional Dispatch Data received to determine if:

- a) they reflect the provision of sufficient energy and Ancillary Services to enable the SO to maintain Reliability of the SO-controlled Grid throughout the corresponding Dispatch Day, taking account of load forecast

variability and the ability to respond to contingencies, excepting which sections 6.7.5 and 6.7.7 shall apply; and

- b) the total output provided for in all Provisional Balanced Schedules in respect of a Generation Facility is not zero and lies outside the possible range defined by either $Q(0)$ to $Q(n_{max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, in which case section 6.7.2 shall apply.

6.7.2 Where section 6.7.1(b) applies, the SO shall promptly notify the Market Participant for the Generation Facility of the discrepancy and of the Provisional Balanced Schedules that contribute to such discrepancy. Such Market Participant shall notify each Market Participant that submitted such a Provisional Balanced Schedule accordingly.

6.7.3 A Market Participant may, by 13:00 on the Day Ahead:

- a. submit revised Provisional Dispatch Data, if that market Participant has received a notice under section 6.7.2 with respect to its Generation Facility;
- b. submit a revised Provisional Balanced Schedule, if that Market Participant has been notified by the Market Participant for the Generator under section 6.7.2; or
- c. submit a new Provisional Balanced Schedule if the need for such a schedule could not have been known by the deadline noted in section 6.6.3.

6.7.4 The SO shall use any accepted new or revised Provisional Dispatch Data or Provisional Balanced Schedule provided by a Market Participant under section 6.7.3 in preparing the Provisional Commitment Schedule under section 6.8.

6.7.5 If, by 12:00 on the Day Ahead or at any time thereafter the SO identifies any residual actual or potential shortfall in the resources necessary to meet forecast load, scheduled exports, Ancillary Services, load forecast variability and potential contingencies, it shall issue an instruction:

- a) to the Market Participant for any Capacity Resource within New Brunswick to the effect that the Capacity Resource is required to be able to synchronise to the SO-controlled Grid, on two hours notice, at any time of the Dispatch Day that is more than ten hours from the time of the issuance of the instruction; and
- b) to the Market Participant for any Capacity Resource outside New Brunswick to the effect that the Market Participant for that Capacity Resource is required to submit, or to have submitted, a Balanced Schedule for the import of the Capacity Obligation quantity from that Capacity Resource throughout the hours specified by the SO.

6.7.6 A Market Participant that is issued an instruction:

- a) under section 6.7.5(a) shall, at its own expense, ensure that any applicable Capacity Resource is ready to synchronize to the SO-controlled Grid on two hours' notice and to ramp up at its full ramp rate immediately thereafter, is ready to provide any Ancillary Service for which it has an Ancillary Services contract, including an Ancillary Services contract referred to in section 6.2, or both, as may be applicable; or
- b) under section 6.7.5(b) shall submit or have submitted a Balanced Schedule as required and shall arrange for the sale of such energy, all at its own expense.

6.7.6A Any failure by a Capacity Resource to perform in accordance with an instruction given under section 6.7.6, other than as a result of a Forced Outage, shall be subject to a penalty of up to twice the per annum long run marginal cost of gas

- turbine peaking plant capacity for the quantity of the resulting shortfall. Notwithstanding section 3.4.3(c), in no event shall such penalty be, for any occurrence of a failure, less than ten percent of the maximum penalty that may be imposed by the SO. Where the SO is required as a result of the failure to curtail firm load, the SO shall impose the maximum penalty. In all other cases, in determining the amount of the penalty, the SO shall have regard to the diligence demonstrated by the Market Participant in attempting to rectify the failure and to the other criteria referred to in section 3.4.4.
- 6.7.7 If, by 12:00 on the Day Ahead or at any time thereafter, after accounting for any instructions issued under section 6.7.5, the SO identifies any actual or potential shortfall in the resources necessary to meet forecast load, scheduled exports, Ancillary Services, load forecast variability and potential contingencies, it shall give notice to Market Participants for Interruptible Load Facilities that their Interruptible Load Facilities may be subject to interruption on one hour's notice at any time during the corresponding Dispatch Day.
- 6.7.8 A Market Participant that receives notice under section 6.7.7 that its Interruptible Load Facility may be interrupted shall at its own expense make all such arrangements as may be required to enable it to interrupt such load on one hour's notice.
- 6.7.9 Any failure to make the arrangements or to effect the interruption referred to in section 6.7.7 upon being requested to do so shall be subject to a penalty of up to twice the per annum long run marginal cost of gas turbine peaking plant capacity for the quantity of the deficiency in load interruption. Notwithstanding section 3.4.3(c), in no event shall such penalty be, for any occurrence of a failure or of a deficiency in interruption, less than ten percent of the maximum penalty that may be imposed by the SO. Where the SO is required as a result of the failure to curtail firm load, the SO shall impose the maximum penalty. In all other cases, in determining the amount of the penalty, the SO shall have regard to the diligence demonstrated by the Market Participant in attempting to rectify the failure or deficiency and to the other criteria referred to in section 3.4.4.

6.7.10 Where, in performing its obligations under this section 6.7, the SO anticipates the occurrence of a loss of Reliability of the SO-controlled Grid that may affect the supply of electricity to or from the Point Lepreau nuclear Generation Facility, the SO shall promptly so notify the Market Participant for that Generation Facility.

6.8 Provisional Commitment Schedule

6.8.1 The SO shall, on the Day Ahead, optimize dispatch for the 24 hours of the corresponding Dispatch Day on the basis of accepted Provisional Dispatch Data and Provisional Balanced Schedules, its Ancillary Service requirements, self-supplied Ancillary Services and their provision by Generation Facilities, forecast load, scheduled exports, load forecast variability, potential contingencies and the status of the SO-controlled Grid, including Outages and limits. On that basis, the SO shall prepare a Provisional Commitment Schedule for that Dispatch Day. In preparing the Provisional Commitment Schedule, the SO shall base the energy and Ancillary Services requirements on its own best estimates, including load forecast variance and reserves, and shall have regard to but not be bound by Provisional Balanced Schedules.

6.8.2 If, in preparing the Provisional Commitment Schedule, the SO identifies any Generation Facility for which the total output in all Provisional Balanced Schedules, including allowance for any self-supplied Ancillary Services to be provided by such Generation Facility, is not zero and lies outside the possible range defined by either $Q(0)$ to $Q(n_{max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, the SO shall promptly notify the Market Participant for the Generation Facility of the discrepancy and of the Provisional Balanced Schedules that contribute to such discrepancy. Such Market Participant shall notify each Market Participant that submitted such a Provisional Balanced Schedule accordingly.

6.8.3 Where section 6.8.2 applies, the SO shall also automatically make the following adjustments:

- a) the Provisional Dispatch Data for the Generation Facility shall be adjusted by setting to zero the re-dispatch price for energy up to either $Q(0)$ or, if applicable, to the load profile determined by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time; and
- b) the applicable Provisional Balanced Schedule quantities for the relevant hours and the applicable Generation Facility shall be adjusted in accordance with the instructions provided by the Market Participant for the Generation Facility, or in the absence of such instructions, proportionately reduced so as not to exceed $Q(n_{\max})$.

6.8.4 The SO shall, by 14:00 on the Day Ahead, make available to each Market Participant the Provisional Commitment Schedule in respect of its own Generation Facilities and energy transactions for the corresponding Dispatch Day.

6.8.5 The SO shall, by 14:00 on the Day Ahead, make available to each Transmitter whose Transmission System forms part of the SO-controlled Grid or to the person controlling the operation of Transmission switching for that Transmission System, a provisional switching schedule indicating any Transmission switching operations requiring implementation during the corresponding Dispatch Day.

6.8.6 The SO shall, by 14:00 on the Day Ahead, Publish aggregated information regarding the Provisional Commitment Schedule for the corresponding Dispatch Day.

6.9 Day Ahead Final Input and Commitment Schedule

6.9.1 Subject to sections 6.9.2 and 6.9.3 and to continued compliance with any instruction issued under section 6.7.5(b), a Market Participant may, at any time prior to 15:00 on the Day Ahead, update its Provisional Balanced Schedule or Provisional Dispatch Data for the corresponding Dispatch Day by submitting a revised Provisional Balanced Schedule or revised Provisional Dispatch Data. Such revised Provisional Balanced Schedule or revised Provisional Dispatch

- Data shall comply with section 6.5.1 or 6.5.2, respectively and shall, if accepted by the SO, supersede all earlier Provisional Balanced Schedules or Provisional Dispatch Data.
- 6.9.2. Each Market Participant shall ensure that any revised Provisional Dispatch Data covers the entire Committed Capacity of each of its Capacity Resources and allows for the continued fulfilment by each of its Capacity Resources of all obligations of those Capacity Resources.
- 6.9.3 A Market Participant may revise its Provisional Dispatch Data without the prior approval of the SO only to the extent that the revision does not change any quantity or price by more than 10 percent relative to the previously accepted Provisional Dispatch Data. The SO shall approve a change in quantity or price of more than 10 percent unless the SO determines that such change would threaten the Reliability of the SO-controlled Grid.
- 6.9.4 Accepted Provisional Balanced Schedules and Provisional Dispatch Data, including those revised and accepted under section 6.9.1 where applicable, shall become the Final Day Ahead Balanced Schedule or FDABS and Final Day Ahead Dispatch Data or FDADD at 15:00 on the Day Ahead.
- 6.9.5 The SO shall, on the Day Ahead, re-optimize the dispatch for the 24 hours of the corresponding Dispatch Day in accordance with Final Day Ahead Dispatch Data and Final Day Ahead Balanced Schedules, its updated Ancillary Service requirements, updated forecast load, scheduled exports, load forecast variability and potential contingencies, and the updated status of the SO-controlled Grid, including Outages and limits. On that basis, the SO shall prepare a Final Day Ahead Commitment Schedule or FDACS. In preparing the Final Day Ahead Commitment Schedule, the SO shall base the energy and Ancillary Services requirements on its own best estimates, including load forecast variance and reserves, and shall have regard to but not be bound by Final Day Ahead Balanced Schedules.

6.9.6 If, in preparing the Final Day Ahead Commitment Schedule, the SO identifies any Generation Facility for which the total output in all Final Day Ahead Balanced Schedules, including allowance for any self-supplied Ancillary Service to be provided by that Generation Facility, is not zero and lies outside the possible range defined by either $Q(0)$ to $Q(n_{max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, the SO shall promptly notify the Market Participant for the Generation Facility of the discrepancy and of the Final Day Ahead Balanced Schedules that contribute to such discrepancy. Such Market Participant shall notify each Market Participant that submitted such a Final Day Ahead Balanced Schedule accordingly.

6.9.7 Where section 6.9.6 applies, the SO shall also automatically make the following adjustments:

- a) the Dispatch Data for the Generation Facility shall be adjusted by setting to zero the re-dispatch price for energy up to either $Q(0)$ or, if applicable, to the load profile determined by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time; and
- b) the applicable Final Day Ahead Balanced Schedule quantities for the relevant hours and the applicable Generation Facility shall be adjusted in accordance with the instructions provided by the Market Participant for the Generation Facility, or in the absence of such instructions, proportionately reduced so as not to exceed $Q(n_{max})$.

6.9.7A Where section 6.9.6 does not apply, the SO shall use in its optimisation a unit cost of energy equal to the Generation Facility's MRC divided by the Generation Facility's MRQ for all energy that is below the Generation Facility's MRQ and that is scheduled during ramp-up and ramp-down of the Generation Facility.

6.9.8 The SO shall, by 16:00 on the Day Ahead, make available to each Market Participant the FDACS in respect of its own Generation Facilities, Bid-Based

Demand Response bids, Ancillary Service supply from a Load or Joint Facility, and energy transactions for the corresponding Dispatch Day.

6.9.9 The SO shall, by 16:00 on the Day Ahead, make available to any Transmitter whose Transmission System forms part of the SO-controlled Grid or to the person controlling the operation of Transmission switching for that Transmission System, a final switching schedule, indicating any Transmission switching operations requiring implementation during the corresponding Dispatch Day and including instructions regarding the arming or disarming of Special Protection Systems.

6.9.10 The SO shall, by 16:00 on the Day Ahead, Publish aggregated information regarding the FDACS for the corresponding Dispatch Day.

6.9.11 Each Market Participant that has submitted Dispatch Data in respect of a Generation Facility, Bid-Based Demand Response bids, or Ancillary Service supply from a Load or Joint Facility, shall, by 18:00 on the Day Ahead, acknowledge receipt of the FDACS in respect of each of its Generation Facilities, Bid-Based Demand Response, or Ancillary Service supply from a Load or Joint Facility in the manner prescribed by the SO.

6.9.12 Each Market Participant shall prepare and, subject to section 6.12, synchronize its Generation Facilities to the SO-controlled Grid and schedule Interconnection transactions with other Control Areas in compliance with NERC tagging requirements in order to fulfill its commitments as described in the FDACS for the coming Dispatch Day.

6.10 Changes and Deviations

6.10.1 The SO shall update its load forecasts for the Dispatch Day and its Ancillary Services requirements as it determines appropriate.

6.10.2 If the SO becomes aware of any circumstance that will or is likely to prevent the SO from dispatching resources generally in accordance with the FDACS, it shall promptly notify all affected Market Participants and, if appropriate, any applicable

Transmitter, of the circumstances and of the likely impacts of such circumstances on their facilities, Bid-Based Demand Response bids, Ancillary Service supply from a Load or Joint Facility, and energy transactions.

6.10.3 If a Market Participant becomes aware of any circumstance that will or is likely to prevent that Market Participant from fulfilling its commitments as described in a FDACS or any update thereto issued by the SO, it shall promptly notify the SO of the circumstances and of the likely consequences of such circumstances. To the extent that the Market Participant has the means to mitigate the impact of such circumstances, it shall propose such means to the SO, which may include:

- a) rescheduling of its own Facilities, Bid-Based Demand Response bids, or Ancillary Service supply from a Load or Joint Facility;
- b) in the case of transactions using Point-to-Point Service, re-designating either or both the Point of Receipt and the Point of Delivery, as those terms are defined in the Transmission Tariff;
- c) cancelling planned export transactions;
- d) scheduling of imports; or
- e) scheduling of backup supply from other Market Participants.

The Market Participant shall promptly submit to the SO for the SO's acceptance revisions to its Balanced Schedule or Dispatch Data, as the case may be, that reflect such mitigation measures.

6.10.4 Where the SO, in its sole discretion, does not accept the mitigation measures or revisions referred to in section 6.10.3 or in section 6.10.4(a), the SO may require the Market Participant to:

- a) propose additional and/or alternative mitigation measures; or

- b) take such additional and/or alternative mitigation measures as may be directed by the SO.
- 6.10.5 Where section 6.10.4 applies, the Market Participant shall promptly take the action required and submit to the SO revisions to its Balanced Schedule or Dispatch Data, as the case may be, that reflect such additional and/or alternative mitigation measures.
- 6.10.5A The Market Participant for a hydraulic Generation Facility may, at any time, submit changes to Dispatch Data in respect of all hours commencing more than 2 hours after the submission of such Dispatch Data. Such changes shall be restricted to increases in the quantity $Q(1)$ and equal increases in the quantities $Q(2)$ to $Q(n_{max})$. Such changes may also include decreases in the quantities $Q(1)$ to $Q(n_{max})$ submitted after the occurrence of, and prior to recovery from, a contingency that is a reportable event as defined by NPCC.
- 6.10.5B A Market Participant for a Generation Facility may at any time submit to the SO revisions to its Dispatch Data for hours commencing more than 1 hour after the submission of such revisions. Such changes shall be restricted to changes in $P(1)$ to $P(n_{max})$ and $Q(1)$ to $Q(n_{max})$. The SO shall approve such requests unless the SO determines that such a change would threaten the Reliability of the SO controlled grid.
- 6.10.6 A Market Participant for a wind driven Generation Facility may provide to the SO:
- a) telemetry data in respect of wind; and
 - b) rules by which the SO should revise values for Q submitted under sections 6.5.3 and 6.5.4.
- 6.10.7 The SO may accept the wind telemetry data and rules submitted under section 6.10.6 and may from time to time adjust the Dispatch Data for the wind driven Generation Facility in accordance with such rules. The SO shall be entitled to rely on such data and rules as submitted by the Market Participant for such Generation Facility and, notwithstanding section 1.14, the SO shall have no

liability to such Market Participant or any other person arising directly or indirectly from the acceptance of any such data or the application of any such rules. The Market Participant submitting such data and rules shall, notwithstanding section 1.14, indemnify and hold harmless the SO in respect of all claims, losses, costs, liabilities, obligations, actions, judgments, suits, expenses, disbursements or damages arising directly or indirectly from the acceptance of such data or the application of such rules by the SO.

6.10.8 Subject to continued compliance with any instruction issued under section 6.7.5(b), a Market Participant may submit a balanced late change request in respect of its Balanced Schedule up to 30 minutes prior to the start of the Dispatch Hour to which such late change request relates. The SO may reject any late change request in respect of a Balanced Schedule unless it can be accommodated in the corresponding Commitment Schedule for a Generation Facility without reducing the capability of that Generation Facility to supply Ancillary Services scheduled in the FDACS or in any later Commitment Schedule. The SO shall otherwise accept such late change request provided that the SO-controlled Grid is in a normal operating condition and the SO is satisfied that such acceptance will not threaten Reliability of the SO-controlled Grid or of a Zone. Subject to section 6.10.8A, the Balanced Schedule incorporating all such late change requests as have been accepted by the SO shall be the Final Hourly Balanced Schedule or FHBS for the applicable Dispatch Hour. Where no such late change requests have been accepted by the SO for a given Dispatch Hour, the Balanced Schedule existing at 30 minutes prior to the start of the Dispatch Hour shall, subject to section 6.10.8A, be the Final Hourly Balanced Schedule for that Dispatch Hour. The SO shall inform each Market Participant of the Final Hourly Balanced Schedule in respect of that Market Participant's transactions.

6.10.8A The SO may adjust a FHBS for settlement purposes to take account of:

- a) the failure of any Balanced Schedule to pass check-out with other Control Area Operators;

- b) the curtailment of any transaction underlying a Balanced Schedule as a result of transmission loading relief effected in accordance with NERC standards and practices; or
- c) the recall of any export or import transaction in accordance with the relevant provisions of the Balanced Schedule and Interconnection Agreements, including in respect of Operating Reserve and unit contingent import transactions, but not unit contingent export transactions recalled as a result of the associated unit contingency event.

6.10.9 Where any one or more of section 6.10.2, 6.10.3 or 6.10.7 apply, the SO shall assess the need to update a Market Participant's Commitment Schedule relative to the FDACS, or its ability to accommodate the necessary changes through the hour ahead and real time dispatch processes described in sections 6.13 and 6.14. In the event that the SO determines that it needs to update a Commitment Schedule relative to the FDACS, such update shall be done on the basis of the applicable Final Day Ahead Balanced Schedules and Final Day Ahead Dispatch Data, modified to accommodate the changes required to mitigate the change in circumstances that triggered the need to update the commitment schedule.

6.10.10 If, in preparing an updated commitment schedule or in preparing the Final Hourly Commitment Schedule referred to in section 6.10.12, the SO identifies any Generation Facility for which the total output in all Final Hourly Balanced Schedules, including allowance for any self-supplied Ancillary Services to be provided by such Generation Facility, is not zero and lies outside the possible range defined by either $Q(0)$ to $Q(n_{max})$ or, if applicable, by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time, the SO shall promptly notify the Market Participant for the Generation Facility of the discrepancy and of the Final Hourly Balanced Schedules that contribute to such discrepancy. Such Market Participant shall notify each Market Participant that submitted such a Final Hourly Balanced Schedule.

6.10.11 Where section 6.10.10 applies, the SO shall also automatically make the following adjustments:

- a) the Final Day Ahead Dispatch Data for the Generation Facility shall be adjusted by setting to zero the re-dispatch price for energy up to either $Q(0)$ or, if applicable, to the load profile determined by the Generation Facility's registration data with respect to ramping, its Minimum Run Quantity and its Minimum Run Time; and
- b) the applicable Final Hourly Balanced Schedule quantities for the relevant hours and the applicable Generation Facility shall be adjusted in accordance with the instructions provided by the Market Participant for the Generation Facility, or in the absence of such instructions, proportionately reduced so as not to exceed $Q(n_{\max})$.

6.10.11A Where section 6.10.10 does not apply, the SO shall use in its optimisation a unit cost of energy equal to the Generation Facility's MRC divided by the Generation Facility's MRQ for all energy that is below the Generation Facility's MRQ and that is scheduled during ramp-up and ramp-down of the Generation Facility.

6.10.12 The SO shall, commencing 30 minutes prior to the start of each Dispatch Hour, adopt as Final Hourly Dispatch Data the Final Day Ahead Dispatch Data, as modified where applicable by accepted changes under sections 6.10.3, 6.10.4, 6.10.5A, and/or 6.10.7. The SO shall prepare a Final Hourly Commitment Schedule or FHCS for the Dispatch Hour, together with an updated Commitment Schedule for up to three hours following the Dispatch Hour using:

- a) the facility commitment data derived from the Final Day Ahead Commitment Schedule, as modified as appropriate in accordance with sections 6.10.9 and 6.11.1;
- b) the information referred to in section 6.10.1;

- c) the FHBS modified to take account of the following circumstances inasmuch as they may be known at the time of preparation of the FHCS:
 - i) the failure of any Balanced Schedule to pass check-out with other Control Area Operators; and
 - ii) the curtailment of any transaction underlying a Balanced Schedule as a result of transmission loading relief effected in accordance with NERC standards and practices; and
- d) the Final Hourly Dispatch Data.

The SO may, in the event that the circumstances have changed little from one hour to the next or in the event of computation problems, adopt as FHCS for a Dispatch Hour the last Commitment Schedule for that Dispatch Hour as prepared in conjunction with the FHCS for a previous Dispatch Hour.

The SO shall use the FHCS as the basis for the Dispatch Instructions to be issued under section 6.13.1(e).

6.10.13 Where the SO updates a Commitment Schedule under section 6.10.9, and following the preparation of the Final Hourly Commitment Schedule under section 6.10.12, it shall promptly provide notice of and Publish such updated Commitment Schedule, if applicable, and of the Final Hourly Commitment Schedule in accordance with sections 6.9.8, 6.9.9 and 6.9.10. Such notice shall be provided to each Market Participant that has submitted Dispatch Data in respect of a Generation Facility, Bid-Based Demand Response bids, or Ancillary Service supply from a Load or Joint Facility

6.11 Two Hour Review and Control Actions

6.11.1 At least two hours before the start of each Dispatch Hour, and at such other times as the SO considers appropriate, the SO shall review its load forecasts, its Ancillary Service requirements, the status of the SO-controlled Grid, including Outages and limits, and all accepted Dispatch Data and Balanced Schedules. If

in conducting this review the SO identifies any actual or forecast shortage in energy supply or in the provision of an Ancillary Service other than Black Start Capability Service, the SO shall notify all Market Participants and shall take the following actions, in descending order, until such time as the shortage is or can be completely mitigated:

- a) schedule incremental energy from all Capacity Resources scheduled to be operating, up to the limit of their Committed Capacity;
- b) instruct other Capacity Resources to synchronize to the SO-controlled Grid, and dispatch such other Capacity Resources;
- c) on at least one hour's notice, or less notice as specified in relevant contracts, issue load interruption orders in respect of Interruptible Load Facilities;
- d) reject all firm export schedules from Capacity Resources, except to the extent that these are resubmitted as non-firm and subject to interruption at short notice in order that they may be accounted for as contributing to the 10-minute Operating Reserve requirement; and
- e) take such other Control Actions as are provided for in Appendix 6A.

6.11.2 The SO shall, when it takes action under section 6.11.1, Publish notice of that fact. Such Publication need not include any detail as to the specific action taken.

6.11.3 A Market Participant shall promptly acknowledge receipt of, and comply with, any instruction or order received from the SO under section 6.11.1. If a Market Participant is unable to comply in whole or in part with such instruction or order, it shall immediately notify the SO of the reasons for its inability to comply and shall immediately seek and implement measures by which it can comply with the maximum extent possible. The Market Participant shall promptly notify the SO of each measure implemented and of the extent of compliance achieved as a result.

6.11.4 Where, in performing its obligations under this section 6.11, the SO anticipates the occurrence of a loss of Reliability of the SO-controlled Grid that may affect the supply of electricity to or from the Point Lepreau nuclear Generation Facility, the SO shall promptly so notify the Market Participant for that Generation Facility.

6.12 Generator Synchronization, De-synchronization and Switching Devices

6.12.1 No Market Participant shall synchronize a Generation Facility to the SO-controlled Grid or close any switching device at the point at which the Generation Facility is connected to the SO-controlled Grid, or de-synchronize a Generation Facility from the SO-controlled Grid or open any switching device at the point at which the Generation Facility is connected to the SO-controlled Grid, unless:

- a) the Market Participant has requested and the SO has approved such synchronization or closing or such de-synchronization or opening;
- b) the synchronization or closing or the de-synchronization or opening is being effected on the instruction or order of the SO; or
- c) the Generation Facility is suffering a Forced Outage.

6.12.2 The SO shall respond to all synchronization or closing and all de-synchronization or opening requests within two hours of receipt and in the order in which they were received. The SO shall endeavour, but shall not be obliged, to provide a faster response for requests received less than two hours prior to the proposed time of synchronization or closing or of de-synchronization or opening.

6.12.3 A synchronization or closing or a de-synchronization or opening request shall be approved by the SO unless the SO determines that such approval would threaten Reliability of the SO-controlled Grid or of any Zone.

6.13 Hour Ahead Dispatch

6.13.1 During the hour prior to the start of each Dispatch Hour, the SO shall:

- a) update its load forecasts;
- b) update its Ancillary Service requirements;
- c) update the status of the SO-controlled Grid, including Outages and limits;
- d) review Interconnection transactions, and confirm or deny approval in accordance with applicable Interconnection Agreements and the relevant standards of applicable Standards Authorities; and
- e) no less than ten minutes prior to the start of the Dispatch Hour, issue required Dispatch Instructions to Market Participants in respect of Generation Facilities, Bid-Based Demand Response bids, or Ancillary Service supply from a Load or Joint Facility.

6.13.2 Dispatch Instructions issued for Generation Facilities under section 6.13.1(e)

may include:

- a) instructions to operate at a given level of net output;
- b) instructions to ramp up or down at given rates over a given period or until reaching a given level of output;
- c) if the Generation Facility is the subject of an Ancillary Service contract for the provision of AGC Service, instructions to supply a particular range of AGC from the Generation Facility or a particular generation unit and to enable the SO to directly control such Generation Facility or generation unit;
- d) if the Generation Facility is the subject of an Ancillary Service contract for the provision of Load Following Service, instructions to supply a given range of regulation or load following from the Generation Facility or a particular generation unit and to enable the SO to control such Generation Facility or generation unit by direct control or by issuing additional control instructions, as required, in respect of output settings;

- e) if the Generation Facility is the subject of an Ancillary Service contract for the provision of Operating Reserve Service, notice that the Generation Facility or a particular generation unit is designated to supply certain quantities of each class of Operating Reserve, which may then be activated for the supply of energy; and
- f) if the Generation Facility is the subject of an Ancillary Service contract for the provision of Reactive Power/Voltage Support Service, instructions to operate the Generation Facility or a particular generation unit at a particular voltage level, power factor or level of reactive power output or absorption.

Any instructions or notice provided by the SO under any one or more of sections 6.13.2(c) to 6.13.2(f) shall comply and be consistent with the provisions of any Ancillary Services contract applicable to the Generation Facility, including any Ancillary Services contract referred to in section 6.2.

6.13.2A The SO may also issue Dispatch Instructions under section 6.13.2 f) at any time.

6.13.2B Dispatch Instructions issued for Bid-Based Demand Response bids under section 6.13.1(e) may include instructions to reduce load by a given amount, or instructions permitting the load reduction to be terminated.

6.13.2C Dispatch Instructions issued for Ancillary Service supply from a Load or Joint Facility under section 6.13.1(e) may include instructions to reduce load by a given amount, instructions permitting the load reduction to be terminated, or notice that the Facility is designated to supply certain quantities of each class of Operating Reserve, which may then be activated for the supply of energy. Any instructions or notice provided by the SO under this section shall comply and be consistent with the provisions of the applicable Ancillary Services contract.

6.13.3 Each Market Participant shall acknowledge receipt of its Dispatch Instructions and shall use its best efforts to operate its Generation Facilities, Bid-Based Demand Response, or Ancillary Service supply from a Load or Joint Facility exactly in accordance with such Dispatch Instructions. The Market Participant shall, in any event, operate its Generation Facilities within the tolerance band described in section 6.13.4 or in accordance with the compliance requirements referred to in section 6.13.5, as applicable.

6.13.3A Dispatch Instructions continue in effect until superseded by later Dispatch Instructions, by activation of Operating Reserve, or by other direction by the SO.

6.13.3B In the event that a Market Participant does not receive a Dispatch Instruction at a time when it reasonably expects to receive such a Dispatch Instruction, it shall promptly contact the SO for clarification.

6.13.4 The tolerance band for compliance with energy Dispatch Instructions shall be the greater of +/- 10 MW or 3% of (i) the dispatched output level in the case of a Generation Facility, or (ii) the load reduction in the case of Bid-Based Demand Response or Ancillary Service from a Load or Joint Facility.

6.13.5 The compliance requirements for the provision of an Ancillary Service shall be as set forth in the applicable Ancillary Service contract, including an Ancillary Service contract referred to in section 6.2.

6.13.6 If a Market Participant becomes aware of any circumstance that will or is likely to prevent that Market Participant's Generation Facility, Bid-Based Demand Response, or Ancillary Service supply from a Load or Joint Facility from complying with its Dispatch Instructions in accordance with sections 6.13.4 and 6.13.5, the Market Participant shall promptly notify the SO of the reasons for the inability to comply and of the consequences of such inability. In such cases, the SO may take such action as may be permitted by this Chapter.

6.14 Real Time Operation

6.14.1 During each Dispatch Hour the SO shall, in accordance with the Dispatch Instructions issued under section 6.13.2 and with the provisions of applicable Ancillary Services contracts, where applicable, including Ancillary Services contracts referred to in section 6.2:

- a) perform AGC;
- b) issue control instructions in respect of the output settings of Generation Facilities designated to provide Load Following Service;
- c) monitor the status of the SO-controlled Grid, including Outages and limits;
- d) activate Operating Reserve;
- e) direct the operation of Transmission Systems;
- f) activate actions through an SPS; and
- g) initiate such Control Actions as may be required to maintain Reliability of the SO-controlled Grid and of any Zone.

6.14.2 Where, during a Dispatch Hour, the SO anticipates the occurrence of a loss of Reliability of the SO-controlled Grid that may affect the supply of electricity to or from the Point Lepreau nuclear Generation Facility, the SO shall promptly so notify the Market Participant for that Generation Facility.

6.15 Forced Outages (including forced de-ratings)

6.15.1 A Transmitter or Market Participant may take whatever reasonable action it deems necessary for reasons of safety, to protect its equipment from immediate material harm or to prevent serious environmental damage arising from unforeseeable events. Such action may include a Forced Outage of a Generation Facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or a Transmission facility. The SO may include in a Market Procedure the circumstances under which action may or

- may not be taken by a Transmitter or a Market Participant under the authority of this section 6.15.1.
- 6.15.2 Where a Transmitter or Market Participant becomes aware that its Transmission facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility will or may suffer a Forced Outage, the Transmitter or Market Participant shall provide to the SO as much advance notice of the Forced Outage as may be practicable in the circumstances, and shall provide such related information as the SO may require. Where advance notice is not practicable in the circumstances, the Transmitter or Market Participant whose Transmission facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility suffers a Forced Outage shall promptly report such event to the SO, together with such related information as the SO may require.
- 6.15.3 A Transmitter or Market Participant whose Transmission facility, Bid-Based Demand Reponse, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility suffers a Forced Outage shall, subject to the SO's approval, seek to return such facility or load reduction capability promptly to full service.
- 6.15.4 A Transmitter or Market Participant whose Transmission facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility suffers a Forced Outage shall, within two Business Days of the commencement of the Forced Outage, provide to the SO a full written report detailing:
- a) the elements or capability forced out of service or de-rated;
 - b) the operating conditions prevailing immediately before the Forced Outage;
 - c) the cause of the Forced Outage;
 - d) the sequence of events in the Forced Outage; and

- e) the remedial action taken or proposed to be taken to return the Transmission facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility to full service and, if applicable, to mitigate the risk of recurrence of the Forced Outage.

6.15.5 If, at the time of preparation of the report referred to in section 6.15.4 the information provided is incomplete relative to the requirements of that section, the Transmitter or Market Participant shall subsequently report the missing information promptly as it becomes available. Without limiting the generality of the foregoing, where the Transmitter or Market Participant has reported proposed remedial action under section 6.15.4(e), it shall promptly report to the SO the remedial action actually taken.

6.15.6 A Transmitter or Market Participant whose Transmission facility, Bid-Based Demand Reponse capability, Ancillary Services provided by Load Facility or Joint Facility, or Generation Facility suffers a Forced Outage shall provide to the SO such additional information as the SO may require and shall provide the SO with access to such records as the SO may consider appropriate for the purpose of assessing the Forced Outage.

6.16 Ancillary Services

6.16.1 The SO shall:

- a) acquire Ancillary Services under contract in accordance with section 5.9 to the extent that they are not self-supplied by Market Participants under section 6.2 or provided by the SO from its own resources;
- b) schedule and dispatch resources to provide Ancillary Services under and in accordance with applicable Ancillary Services contracts, including the Ancillary Services contracts referred to in section 6.2; and

- c) forecast and Publish its Ancillary Service requirements in accordance with this Chapter and Chapter 5.

6.16.2 In optimizing scheduling and dispatch under this Chapter, the SO shall take into account:

- a) the actual price of the provision of Ancillary Services under Ancillary Services contracts; and
- b) the re-dispatch prices submitted as Dispatch Data in accordance with section 6.5.3 and arising from the commitment of additional Generation Facilities and the re-dispatch of energy output levels in order to secure Ancillary Services in addition to energy provided under Balanced Schedules.

6.17 Emergency and High Risk Operating States and Emergency Energy

6.17.1 Where the SO identifies an actual or forecast shortage in the supply of energy or the provision of Ancillary Services other than Black Start Capability Service and invokes section 6.11.1(e), it may in accordance with Appendix 6A declare that all or a part of the SO-controlled Grid is in an Emergency Operating State. While all or part of the SO-controlled Grid is in an Emergency Operating State, the SO may, in order to maintain Reliability of the SO-controlled Grid or of any Zone:

- a) temporarily relax Transmission operating limits from normal to emergency limits;
- b) temporarily violate the 30 minute Operating Reserve requirement;
- c) purchase Emergency Energy under and in accordance with applicable Interconnection Agreements, and charge the associated costs to the Residual Monthly Cost under section 7.8; and
- d) initiate other control actions in accordance with Appendix 6A.

6.17.2 Where the SO identifies or anticipates an increase in the risk of the occurrence of contingency events within the Integrated Electricity System or in an electricity system that is Interconnected with the Integrated Electricity System, or an increase in the consequences of a contingency event that may occur, the SO may declare that all or part of the SO-controlled Grid is in a High Risk Operating State. While all or a part of the SO-controlled Grid is in a High Risk Operating State, the SO may:

- a) temporarily impose more rigorous Transmission operating limits; and
- b) temporarily impose more rigorous Operating Reserve or other Ancillary Service requirements.

6.17.3 Where the SO receives a request for the provision of Emergency Energy under and in accordance with an Interconnection Agreement, it shall sell Emergency Energy to the requesting party subject to the terms of the Interconnection Agreement and to the preservation of the Reliability of the Integrated Electricity System, and it shall credit the revenues from such sale to the Residual Monthly Cost under section 7.8.

6.17.4 Where a curtailment, interruption or reduction of Transmission Service to a Market Participant occurs during an emergency, the SO shall notify each affected Market Participant as soon as practicable of the reasons for the curtailment, interruption or reduction and, if known, its expected duration.

6.18 Publication of System Information

6.18.1 The SO shall Publish the following information on an ongoing basis:

- a) New Brunswick load (MW);
- b) New Brunswick primary Demand (MW); and
- c) the total net import / export schedule (MW).

6.18.2 The SO shall Publish the following historical load information for each hour:

- a) New Brunswick load (MWh);
- b) New Brunswick primary Demand (MWh);
- c) total imports (MWh);
- d) total exports (MWh);
- e) Automatic Generation Control Service scheduled (MWh);
- f) Load Following Service scheduled (MWh);
- g) 10-minute spinning Operating Reserve scheduled (MWh);

- h) 10-minute non-spinning Operating Reserve scheduled (MWh);
- i) 30-minute Operating Reserve scheduled (MWh);
- j) purchases of Emergency Energy (MWh);
- k) sales of Emergency Energy (MWh);
- l) estimated firm load not served (MWh); and
- m) Operating Reserve shortages (MWh).

6.18.3 The SO shall Publish an indication of the estimated FHMC for each hour by 10:00 of the following Business Day.

Appendix 6A -Control Actions

6A.1 Order and Description of Control Actions

6A.1.1 Where the SO identifies an actual or forecast shortage in the supply of energy or the provision of Ancillary Services other than Black Start Capability Service and invokes section 6.11.1(e), it may take one or more of the following Control Actions. These Control Actions are set out in order of priority recognizing that, except as provided for in section 6.11.1, such order of priority is for guidance, and may be over-ridden by the SO's judgment in the exercise of its responsibilities to maintain Reliability:

Column 1: Priority	Column 2: Description	Column 3: Cross Reference
1	Issue public or Market Participant-specific warning notices, if applicable	
2	Manage inadvertent payback	SO internal procedure
3	Manage time-error correction	SO internal procedure
4	Utilize all output from Capacity Resources that are scheduled to be operating	6.11.1(a)
5	Mobilize additional Capacity Resources	6.11.1(b)
6	Interrupt Interruptible Load	6.11.1(c)
7	Reject firm export schedules from Capacity Resources	6.11.1(d)
8	Cancel Planned Outages of Capacity Resources, and recall Capacity Resources on Planned Outages in progress	5.7.8
9	Issue EEA 1	
10	Declare an Emergency Operating State	6.17.1
11	Discontinue any testing or commissioning that reduces the net capability of the Integrated Electricity System	4.7.5

Chapter 6 - Operational Requirements

Column 1: Priority	Column 2: Description	Column 3: Cross Reference
12	Issue EEA 2	
13	Disregard 30 minute Operating Reserve requirement	
14	All export schedules from Capacity Resources to be declared fully recallable and classified as 10-minute non-spinning Operating Reserve and recalled as activation of Operating Reserve if necessary	
15	Recall all exports from Capacity Resources	
16	Purchase Emergency Energy, and seek agreement to adjust Interconnection operating limits if appropriate	
17	Disregard 10-minute non-spinning Operating Reserve requirement	
18	Curtail firm exports, other than from Capacity Resources, in accordance with Interconnection Agreements	
19	Curtail firm load as necessary to preserve ability to withstand worst single contingency	