OEB STAFF INTERROGATORY 11

5.0 Commitments from Previous OEB Decisions

5.1 *Is the IESO's proposed Regulatory Scorecard appropriate?*

5.1 Staff – 11

INTERROGATORY

Reference: Exhibit C-1-1, p. 1

Preamble:

In the Board-approved Settlement for the IESO's2016 Revenue Requirement Submission (EB-2015-0275), Section 6.2, the IESO agreed:

- To consult with intervenors to develop a scorecard for filing in its next Revenue Requirement Submission filed with the Board;
- That the scorecard is intended to be a tool for the Board and intervenors to use in evaluating the IESO's proposed expenditure and revenue requirement; and
- To engage an expert to assist with this work.

Questions:

a) How will the IESO use the Scorecard when finalized to adjust its Corporate Performance Measures (CPMs) going forward – will the IESO still use both?

b) How long does the IESO intend to take to develop the history before it has targets for the Scorecard?

c) What is the potential role for the OEB in reviewing the system view metrics, if any?

RESPONSE

a) The IESO will continue to use both the Regulatory Scorecard and the Corporate Performance Measures because they each serve a different fundamental purpose. The IESO's Corporate Performance Measures are part of its Business Plan and are reported to its Board and management to track progress against the organization's strategic priorities. As noted in Exhibit C-1-1 Attachment 1, page 8 of 56 (i.e., the Elenchus report):

> *…The purpose of IESO's Scorecard Development project is to develop a scorecard that is appropriate for purposes of the IESO's Fees Applications to the OEB. This purpose is related to, but distinct from, the purpose of the IESO existing internal scorecard. The specific OEB-related purpose of this IESO regulatory scorecard is important both to the process that is most appropriate to use in developing it and to the actual performance measures that it will contain.*
>
> *Unlike an internal scorecard that is primarily a management tool, a regulatory scorecard must be considered appropriate by the OEB and ideally is endorsed by stakeholders….*

b) The IESO intends to set targets for those elements of the Regulatory Scorecard that the OEB determines to be useful and that the OEB requires the IESO to include in future filings. Targets for the relevant elements of the scorecard will be set once enough history on the underlying data exists, to enable a realistic and attainable target to be set. Judgement on a case-by-case basis will be required to determine how much history is required before a target can be set. Future filings will include those targets that have been set, and status updates on those that have not.

c) As stated in Exhibit C-1-1, the IESO believes any review of system metrics should occur outside of its Revenue Requirement Submissions for the reasons stated in the Elenchus Report. The IESO is willing to work with parties and the Board outside of this RRS process on the further development of the System View metrics, including identifying where some of the information sought is already or can be made available through the IESO website.

BOMA INTERROGATORY 6

Issue 5.1

INTERROGATORY

Ref: ***Issue 5.1; #8, p23; Customer/Stakeholder Engagement***

(a) Please advise which stakeholders and communities were consulted in 2016; have been consulted in 2017; will be consulted in 2018.

(b) The 2016 sixty-five percent satisfaction rating seems low, as does the two percent targeted increase. Why is the percentage so low? What steps would IESO need to take to increase customer satisfaction from 65% (2016) to 80% in three years? Please discuss fully.

(c) Please provide the survey/study(ies) that establish the sixty-five percent approval rate in 2016, and any other recent customer satisfaction studies.

(d) What steps will IESO take to more quickly increase the percentage of satisfied customers?

(e) How will the proposed two percent increase in satisfaction with the customer engagement process be measured?

(f) How has a stakeholder consultation to date on the Market Renewal Project been reflected in the key Market Renewal Project documents, for example, in the Brattle Group's "Benefits Study"?

RESPONSE

(a) A sample of the forums that the IESO used to engage stakeholders in 2016 and 2017, as well as a generalized list of the types of stakeholders, is provided below. These forums are open to participation from all sectors.

- Stakeholder Advisory Committee (membership is composed of generators, distributors/transmitters, consumers, related businesses/services, Ontario communities)[1].
- Technical Panel (membership includes generators, distributors/transmitters, consumers, and other market participants such as traders and demand response aggregators)[2].

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[1] www.ieso.ca/SAC
[2] www.ieso.ca/TP

- Market Renewal Project(engagement takes place within specific engagement initiatives that are open publically, as well as the Market Renewal Working Group which is composed of generators, distributors/transmitters, consumers, emerging technologies, demand response aggregators, storage and the Market Surveillance Panel)[3].

- Conservation Framework Mid-Term Review (engagement takes place with public sessions and an advisory group which is composed of consumers, distributors and electricity service providers)[4].

A full listing of completed engagement initiatives is available on the IESO's website[5]. Stakeholders who have attended these meetings are reflected in the meeting minutes.

A full listing of all open engagements is available on the IESO's website[6]. Stakeholders who have attended these meetings are reflected in the meeting minutes.

In 2018, the IESO expects to continue to engage with a wide variety of stakeholders through the SAC, Technical Panel, and other engagements and channels such as the Market Renewal Project, Demand Response Working Group, and other initiatives.

Additional stakeholder engagement activities in 2016, 2017 and 2018 are noted below for the areas of the Integrated Regional Resource Plans (IRRPs), Community Engagement and First Nation and Métis Engagement.

IRRPs

Full documentation of the community engagement activities undertaken for the development of the IRRPs released in 2016 and 2017 is provided in each of the IRRP documents, which are available on the IESO's regional planning website[7].

Community Engagement

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[3] http://www.ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal
[4] http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/conservation-framework-mid-term-review
[5] http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/completed/list
[6] http://www.ieso.ca/en/sector-participants/engagement-initiatives/engagements/engagements-status
[7] http://www.ieso.ca/en/get-involved/regional-planning

A full listing of the Local Advisory Committee meetings held by the IESO is available on the IESO website[8]. Community and stakeholder committee members are reflected in the meeting minutes.

In addition to the Local Advisory Committee meetings, below is a sample of the initiatives and forums used to engage communities in 2016 and 2017.

- Municipal meetings and presentations – As part of the bulk and regional electricity planning processes, the IESO regularly meets with municipalities across the province and/or makes presentations to Council or municipal committees
- Workshops – In 2016, the IESO participated in various Quality Urban Energy Systems of Tomorrow (QUEST) Energy Community of Practice Workshops to engage with municipalities on the integration of community energy plans and regional electricity plans
- Open Houses/Public Information Centres – The IESO regularly attends Local Distribution Company open houses and public information centres to engage with the public on the need for projects identified by the IESO
- Conferences – The IESO has engaged with municipal representatives at the following municipal conferences:
    - Association of Municipalities of Ontario
    - Federation of Northern Ontario Municipalities
    - Northwest Ontario Municipal Association
    - Ontario Small and Urban Municipalities
    - Rural Ontario Municipal Association
    - Ontario Professional Planners Institute
    - Economic Developers Council of Ontario

In 2018, the IESO expects to continue to engage with communities and stakeholders through the Local Advisory Committees, municipal meetings and presentations, workshops, open houses, and municipal conferences. During this time, the IESO expects to launch the second round of the regional planning process and will be meeting with municipalities and the LACs to discuss the development of these plans.

<u>First Nation and Métis Engagement</u>

[8] http://www.ieso.ca/LAC

The IESO engages with all First Nation communities and Métis councils through information sharing, hosting of various engagement sessions, working groups, one-on-one meetings, Local Advisory Committees, and attendance at various Indigenous conferences, assemblies and community events.

Throughout 2016 and 2017, the IESO participated in all 17 Indigenous Long-Term Energy Plan (LTEP) engagement sessions to which all First Nation communities and Métis councils were invited. Representatives from over 75 First Nation communities and organizations and 19 Métis Councils attended these sessions.

In 2016 and 2017 the IESO participated in the following Energy Table sessions with the Political Territorial Organizations and the Ministry of Energy:

- First Nation Energy Table meetings with Ontario Regional Chief and the Political Confederacy
- First Nation Energy Table Electricity Bill Working Session with representatives of various First Nations
- Grand Council Treaty 3 Energy Table Sessions

In 2016, the IESO and the 9 Matawa First Nation communities established the Matawa Energy Working Group. The working group has met three times in 2016 and 2017 to date with an additional meeting planned for the fall of 2017.

The IESO has an Aboriginal Energy Working Group whose members include Indigenous individuals who have experience in the energy sector. The AEWG meets 2-3 times per year.

For the remainder of 2017, the IESO will be distributing a newsletter to all First Nation communities and Métis councils that will include an engagement survey and invitations to 6 regional sessions to be held between October and December.

In 2018, the IESO expects to continue to provide opportunities to engage with all 133 First Nation communities and all Métis councils.

(b) The 65 percent stakeholder satisfaction score is a baseline score for the IESO, post-merger. The score is not inconsistent with scores from the IESO, pre-merger.

The score is a composite of the following four attributes:

- Satisfaction with the stakeholder engagement process
- Engagement relevance to stakeholder's business/sector
- IESO meeting stakeholder expectations
- The IESO's perceived commitment to the engagement process as evidenced by interactions with staff.

These four questions are averaged together to derive the overall score. For instance, 84 percent of respondents said their expectations were either met or exceeded, and on overall satisfaction with the process, 50 percent of respondents gave the IESO 8, 9 or 10 out of 10.

The IESO has not contemplated a 5 percent/year increase in score. The 2 percent target increase reflects what the IESO thinks is reasonable within the given resource complement of stakeholder engagement.

(c) Please refer to Attachment 1.

(d) The IESO is working towards achieving the objective of raising the stakeholder satisfaction score by two percent. The IESO's action plan includes writing a stakeholder engagement process for the organization that will be posted externally that will codify the process and expectations of the IESO and stakeholders. It also includes looking and planning for early engagement opportunities, a refresh of IESO communication products (e.g., broadcast emails) and ensuring that stakeholder feedback is considered and responded to in all engagement activities.

(e) The score is a composite of four attributes listed above in part (b) above. The increase will be measured by the same composite.

(f) Stakeholder consultation has been an integral part of the Market Renewal Project and the feedback that has been submitted is reflected in a variety of key documents:

- Stakeholder feedback helped to shape and scope the Benefits Case (please refer to Exhibit I, Tab 1.6, Schedule 5.07, Attachment 1) over the course of the summer and fall of 2016. Brattle and the IESO engaged with stakeholders and the Market Renewal Working Group (MRWG) on three key components: (1) development of the future scenarios, (2) methodology and approach for the analysis, and (3) reflecting and accounting for Ontario's supply mix and unique regulatory and policy framework within the Benefits Case. Two rounds of drafts were reviewed and presented to stakeholders; the drafts were revised in response to over 20 unique sets of comments.

- The Terms of Reference for the MRWG were also developed together with stakeholders. The enhanced collaborative framework including, but not limited to, the establishment of the co-chairs are a direct reflection of stakeholder feedback that the IESO received.

- Stakeholders also played a key role in developing and shaping the Mission and Principles for Market Renewal. The Mission and Principles are available on the IESO website, and noted below. The IESO initially presented the objectives for Market Renewal in April 2016 but in the course of discussions in the Benefits Case, stakeholders asked that these be revisited. Over the course of two meetings along with several individual discussions, the IESO worked closely with the Market Renewal Working Group members and other stakeholders to help to craft a Mission and Principles for Market Renewal that reflected and balanced the diversity of stakeholder views and concerns. The Mission and Principles were developed together with stakeholders and reflect their views and feedback.

  - Mission: Market renewal will deliver a more efficient, stable marketplace with competitive and transparent mechanisms that meet system and participant needs at lowest cost.

  - The themes of the principles include: efficiency, competition, implementability, certainty and transparency. Additional details are available on the IESO's website[9].

[9] http://www.ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal

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Stakeholder Satisfaction Research

Wave 1: Report of Findings

August 23rd, 2016

Introduction

Research Background, Objectives and Our Framework

Background

With the continuing evolution of the IESO including its amalgamation with the Ontario Power Authority, the organization engages with a diverse set of stakeholders ranging from generators to local utilities to non-government organizations.

While diverse in nature, there is also a need to understand and measure the performance of the customer/stakeholder initiatives and track those results over time. As such, the IESO has commissioned Northstar as its research partner to engage with relevant customers/stakeholders and inform internal executives over the course of the contract.

To action against this brief, Northstar has designed a multi-phased, multi-modal approach, a combination of quantitative and qualitative engagements with IESO customers/stakeholders, to be executed from June 2016 through to 2018.

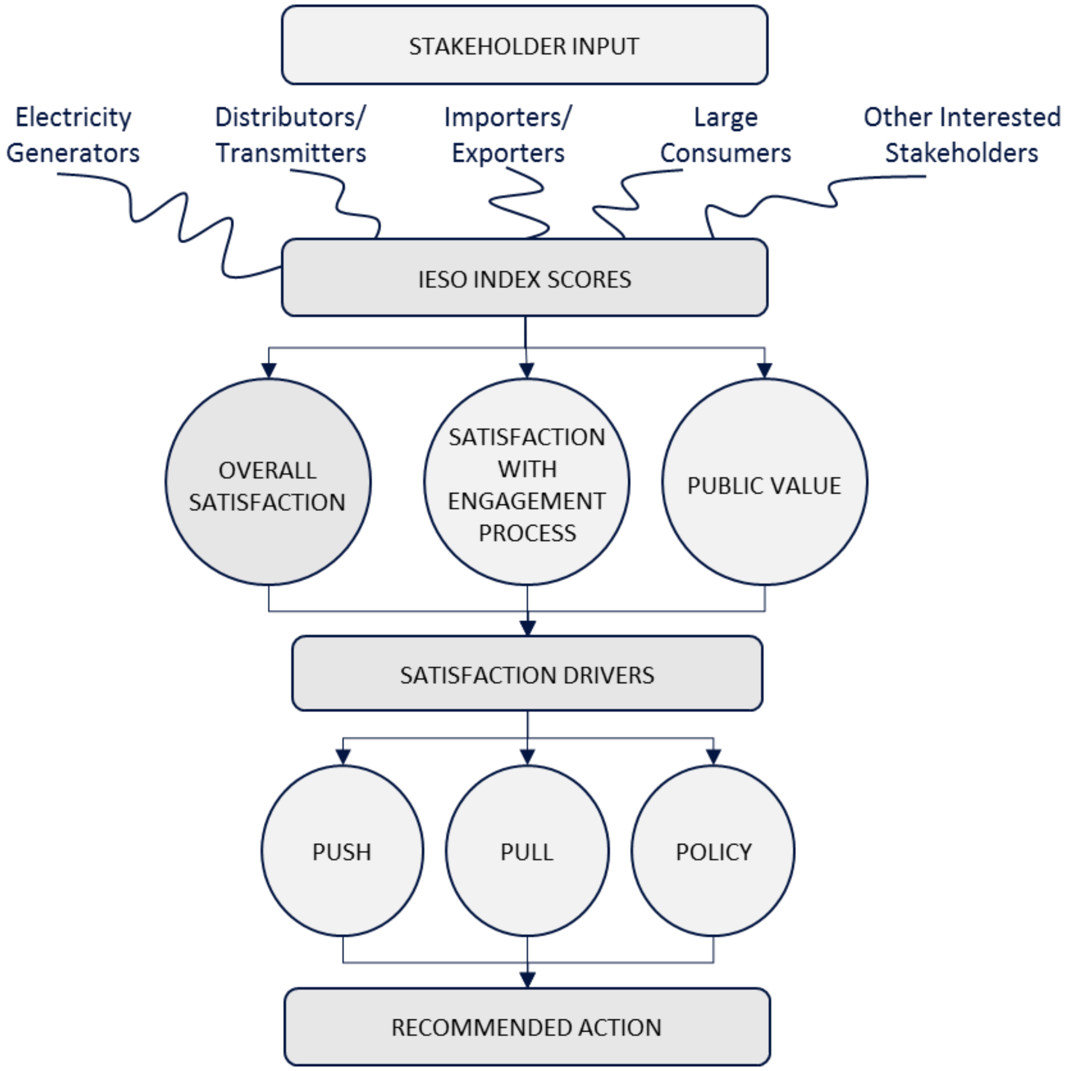
This first wave of quantitative research sampled 271 customers/stakeholders across five key customer groups - Generators, Distributors/Transmitters, Importers/Exporters, Large Consumers and a mixed sub-group of ‘Other’ Interested Stakeholders - to both generate the baseline data set and design the satisfaction index instrument to be used in future waves of research.

Our Index Framework

We have approached the index design with the following underpinning: The index must be sufficiently stable to be tracked over time and sufficiently customized across the five target customer/stakeholder groups.

The graphic adjacent represents the steps we have taken in our data the analysis in this report:

1. IESO Index Scores
2. Satisfaction Drivers
3. Recommended Actions



Research Objectives

More specifically, this first quantitative phase of research is designed to:

•Generate baseline data to be tracked over time on a number of critical metrics (including three index scores) to the IESO organization including:

- Satisfaction with the IESO;
- Satisfaction with the IESO's engagement process;
  - Relevance of the IESO's engagement process;
  - Performance on each of the IESO's engagement process objectives;
- Public Value Assessment
- IESO's communication channel awareness, use and effectiveness;

•Design a satisfaction index based on the key drivers to satisfaction that can be tracked over time;

•Understand the unique drivers of satisfaction and specific recommended actions for each stakeholder group.

Methodology

- In order to maximize response rates, we employed a telephone methodology and conducted interviews with customers/stakeholders from **July 7th to July 29th, 2016**.
  - The average interview length was 24 minutes.
- All study participants were sourced from customer lists, each of which had been in recent contact with the IESO.
  - Sample quotas were set and structured to be representative of available records in the customer lists provided.
- Within the identified field period, we were able to achieve the following number of completes across the five customer groups:

	TOTAL	Electricity Generators	Distributors/ Transmitters	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Total Completes	**271**	**62**	**95**	**14**	**37**	**63**
Sample Quota	400	160	60	60	40	80
Total Usable Records	996	225	319	54	140	258
Response Rate (# of Completes/Total Records)	27%	28%	30%	26%	26%	24%

*NOTE: For the full disposition report of fieldwork, please see appendix.

Reporting Perspective

Circles and squares have been used to distinguish results which are statistically or directionally significant.

= findings which are statistically higher (calculated at a 95% confidence level) among stakeholder target groups vs. the total sample.

= findings which are statistically lower (calculated at a 95% confidence level) among stakeholder target groups vs. the total sample.

= findings which are directionally higher/lower (calculated at a 80-90% confidence level) among stakeholder target groups vs. the total sample.

NOTE: All subsequent research waves will also show significant differences (increases and decreases) between waves of research.

Confidence Intervals	**TOTAL**	Electricity Generators	Distributors/ Transmitters	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Total Completes	271	62	95	14	37	63
+/- % shown = 95% confidence interval	6.0	12.4	10.1	26.2	16.1	12.3

Results are shown among the total sample and profiled across the five groups of stakeholders included. Due to a small base size (n=<20), results reported among the following stakeholder group should be interpreted as directional only:

- Importers/Exporters (n=14)

All derived correlations (key drivers of satisfaction) not included in the main report can be found in the appendix.

Due to small base size (n=<20), we have not conducted derived analysis on the following group:

- Importers/Exporters (n=14)

Executive Summary

Distillation of Implications for IESO

Areas of Investigation: Key Findings

OVERALL SATISFACTION WITH IESO'S PERFORMANCE

- Over half of stakeholders (54%) are very satisfied with the IESO's performance overall - a finding consistent across each of the five stakeholder groups.
- There is a strong relationship across the three metrics shown above meaning that:
- ✓ Increasing satisfaction with the engagement process will also result in an increase in overall satisfaction with the IESO.
- ✓ Appropriately delivering on the organization's list of value objectives will also result in an increase in overall satisfaction.

OVERALL SATISFACTION WITH THE IESO's ENGAGEMENT PROCESS

- While three quarters of stakeholders believe that the success of the stakeholder engagement process is important, just half (50%) are very satisfied with their experience so far.
- The predominant issues centre around transparency, timeliness of communication and flexibility to each group's unique needs.
- Additionally, although most stakeholders feel that the IESO has been effective overall and met their expectations as a trustworthy, reliable and effective organization, they also feel their input is not valued.
- Making engagement more relevant to stakeholders and responding to their needs either through dedicated staff or timely communications will help address this disconnect.

PUBLIC VALUE ASSESSMENT

- The IESO is believed to be putting an appropriate amount of effort and resources behind each of its stated list of objectives indicating that the organization is successfully delivering on public value.
- The impact on satisfaction in not delivering value varies across the organization's list of objectives as does performance.
- As such, the IESO should consider investing most (by way of appropriately delivering) in the following areas:

1. Competitively procuring the resources to meet Ontario's electricity needs today and tomorrow
2. Operating and shaping the electricity system and market in a transparent manner
3. Sharing relevant and valued information, data, analysis and expertise
4. Acting on the input from communities, customers and stakeholders

Areas of Investigation: A Strong Relationship

- Our analysis reveals a strong relationship between each of the three key scores meaning that very few stakeholders are satisfied with the organization overall if they are not satisfied with the overall engagement process and/or believe that the IESO is delivering in public value.
- 31% report high satisfaction with the IESO, high satisfaction with engagement and a high rating on the IESO devoting the right amount of resources to objectives.

SCORE A = HIGH OVERALL SATISFACTION SCORE

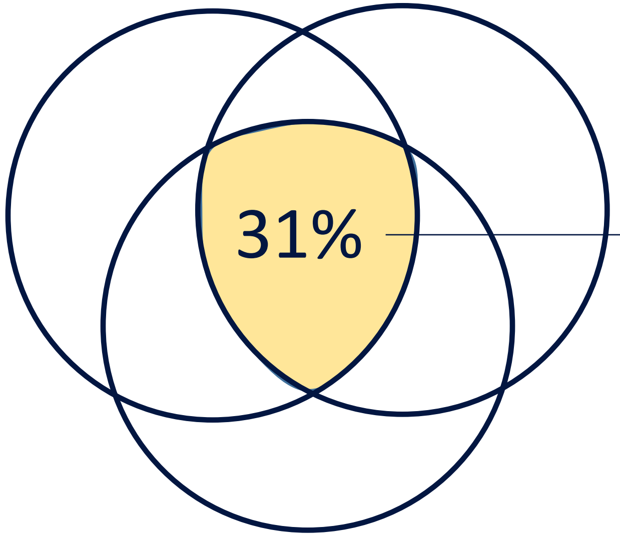
•(Stakeholders who rated their overall satisfaction the IESO's performance an 8 to 10 on a 10-point scale)

SCORE B = HIGH ENGAGEMENT PROCESS SATISFACTION SCORE

•(Stakeholders who rated their satisfaction with the stakeholder engagement process an 8 to 10 on a 10-point scale)

SCORE C = HIGH PUBLIC VALUE COMPOSITE SCORE

•(Stakeholders who believe that the IESO is putting an appropriate amount of effort/resources behind their objectives)



A + B + C

Most frequently, stakeholders give high scores across each metric - identifying the critical need to deliver on all three areas.

NOTE: For detailed scores at each intersection, please see Appendix I.

Areas to Focus On: Push, Pull, Policy

- Our analysis has revealed that the IESO's interactions with stakeholders fall under three broad categories:

PUSH
What the IESO sends out to its stakeholders
(i.e. communications, information, innovation ideas etc.)

PULL
What the IESO takes in from its stakeholders
(general feedback, unique challenges & recommendations toward action)

POLICY
How the IESO positions itself to its stakeholders within the electricity sector more broadly
(i.e. conservation, system reliability, resource management etc.).

	PUSH	PULL	POLICY	
AREAS TO MAINTAIN	• Honesty • Trustworthiness • Effective communications with stakeholders • Providing relevant, meaningful information	• Being fair • Being balanced • Being understanding	• Being a reliable organization • Ensuring a reliable electricity future for Ontario • Consistency	**These are critical drivers of satisfaction and the IESO should continue to perform strongly in each area.**
AREAS WHERE IMPROVED PERFORMANCE WILL INCREASE SATISFACTION	• Timely communications and responsiveness	• Ensuring adequate representation of stakeholder needs • Being open – sharing knowledge and information about how decisions are made • Acting on the input from communities, customers and stakeholders • Flexibility	• Leading the creation of a culture of conservation • Attracting, retaining and developing a highly skilled and professional workforce • Planning for the resources to meet Ontario's electricity needs today and tomorrow • Operating and shaping the electricity system and market in an effective manner	**These are critical drivers of satisfaction and the IESO should aim to perform better in each area.**

Keep In Mind: Stakeholder Context

GENERATORS

- Main challenges revolve around business operations & resource management.
- Most suggestions centre around more 'pull' (listening and engaging) and specialized engagement methods.

*"There should be more focus on **getting efficient results** from **existing resources** ahead of getting new resources. The **market side** and the **contract side could better align their objectives**."*

*"I'd like more one on one meetings because a lot of information is confidential. **IESO needs to be more flexible in adapting market rules and manuals to fit specific entities**."*

DISTRIBUTORS

- Relationship with IESO centres around conservation and operational concerns with some policy input.
- Most feedback relates largely to consistency, pricing, government influence and transparency.

*"Our **biggest challenge is consumer engagement**. We need a firm plan to reduce costs. We are losing consumers to other areas."*

*"**Transparency is a big issue** regarding finances and global adjustment. Providing timely and thorough service to stakeholders is lacking."*

*"I think the **IESO needs a Utility Account Manager, who is consistent**. Sometimes I find there is a **lack of knowledge** which makes things very frustrating."*

LARGE CONSUMERS

- Primarily concerned with transparency, innovation (particularly in sustainable solutions) the development of sustainable energy sources.
- Despite acknowledging the efficiency of their online resources, there is room for improvement in the engagement process.

*"More transparency in how they do electricity forecasting. **They use too much jargon without properly defining or clarifying terminology**. A quick tool explaining what they do instead of big manuals would be an improvement."*

*"I would like to see **more stakeholder workshops**. I feel that they are very successful and engaging for all parties involved."*

*"**Innovation**, community based powers, smaller generation capabilities and **better integration** with LDCs."*

IMPORTERS/ EXPORTERS

- Risk factors concerning this group largely centre around cost, operations and contract renewals.
- Desire for more transparency and greater consideration for those operating within the market is a consistent theme in this group's feedback.

*"**Transparency** in the management and decision making process … be **more receptive to stakeholder proposals** and **more objective** in the way they manage the system."*

*"**Sometimes the IESO takes actions without considering market participants**. Timelines are short to evaluate the decisions and value that the IESO makes."*

'OTHER' INTERESTED STAKEHOLDERS

- Most focused on conservation and the market – including price, procurement and incentives, along with the transparency of IESO.
- Some feel stakeholder input is undervalued and too submissive to government agendas.

*"**Fostering more customer engagement, price and market reform**. They should be doing a lot more to drive a market-based policy."*

*"I would like to see **more transparency** and **easier access** and **process simplification** for outside participants."*

Composite Satisfaction Score

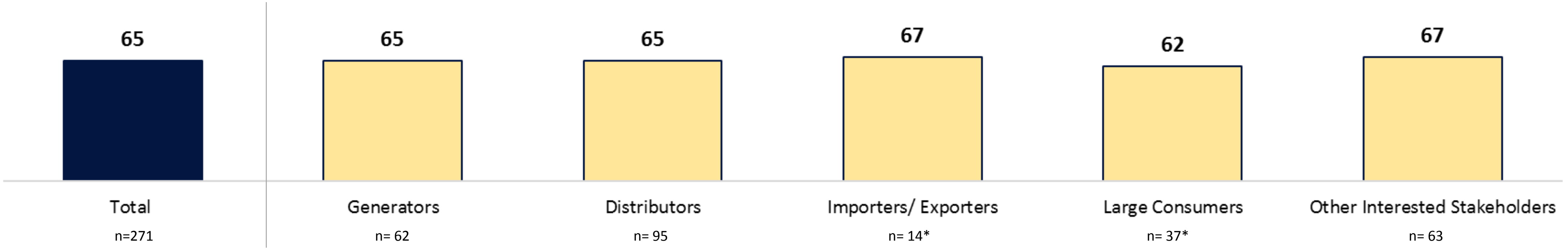
Finally, to act as the baseline against which future performance improvement can be assessed overall, we have created a composite IESO satisfaction score. This score has been calculated through a combination of individual scores on process satisfaction, business relevance, expectations management and culture change:

1. Satisfaction with the engagement process
2. Relevance to stakeholders' business/sector
3. Satisfaction with IESO meeting stakeholder expectations
4. The IESO's perceived commitment to the engagement process as evidenced by interactions with staff

Based on Wave 1 results, the IESO's overall Composite Satisfaction **average** score is 65.

Composite Satisfaction Scores

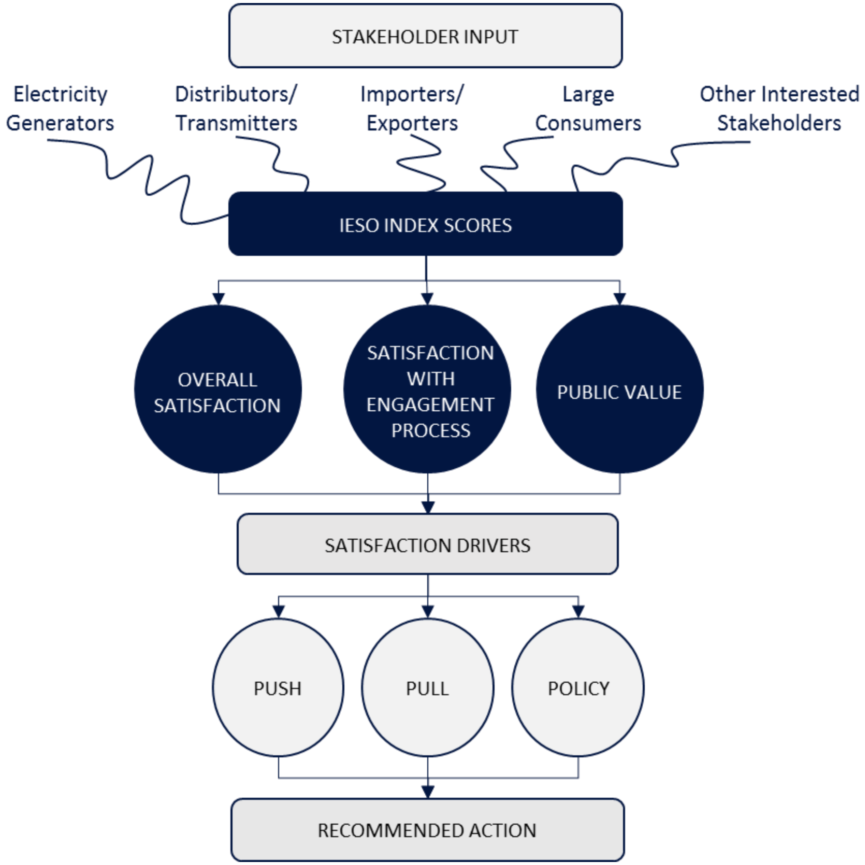
Base: Total Sample (n=271)



2b. Has your experience with the IESO exceeded, met or fallen below your expectations?
6a. As a participant, how satisfied are you with the IESO's engagement process?
7. As a participant, how relevant has the IESO's engagement process been to your business or sector needs? Please consider all of your interactions with the IESO and the various communication channels, programs and initiatives you have engaged with in your answer. Please provide a rating on a 10-point scale where 1 means their processes have not been relevant at all and 10 means they are very relevant. **CHECK ONE ONLY**
10. How well is the IESO's commitment to the engagement process reflected in the staff interactions you have had? Please provide a rating on a 10-point where 1 means this commitment has not at all been reflected and 10 means the commitment has been reflected very well.

Detailed Findings

Index Scores



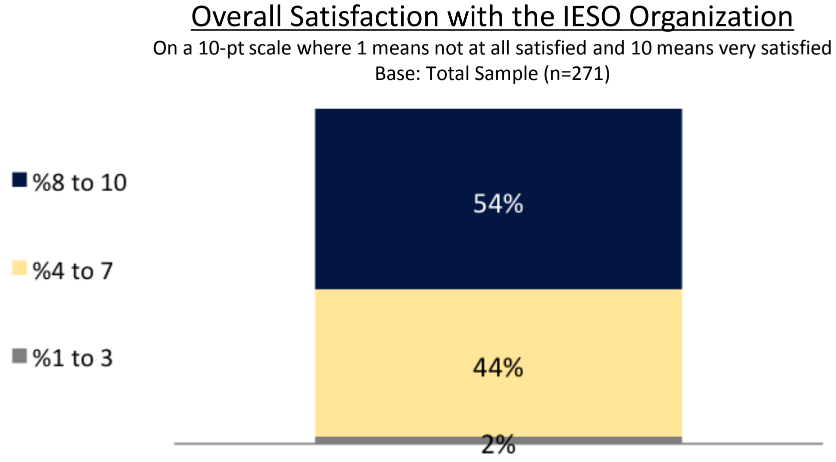
IESO's Overall Satisfaction

How satisfied are stakeholders with IESO's performance overall?

Satisfaction Score

(Dependent Variables)

- IESO customers show a moderate level of satisfaction with the IESO's overall performance, highest among Distributors and lowest among Generators.

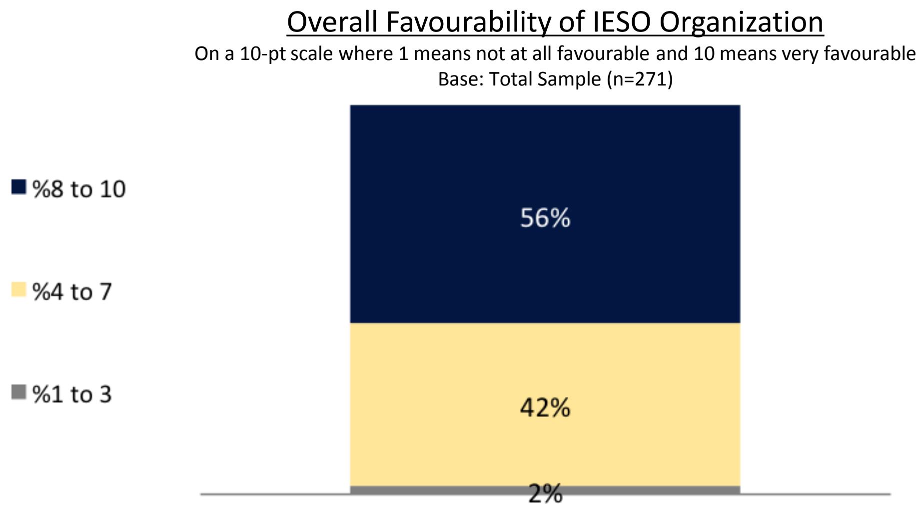


%8 to 10	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
Overall Satisfaction	48	61	50	54	51

2a. Based on your experience, how satisfied are you with the IESO's overall performance? Please use a 10-point scale where 1 means you are not at all satisfied and 10 means you are very satisfied with the IESO.

Organization Favourability

- Nearly two thirds of stakeholders hold a very favourable opinion of the IESO, consistent across target stakeholder groups.



	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37	63
%8 to 10	53	60	50	54	56

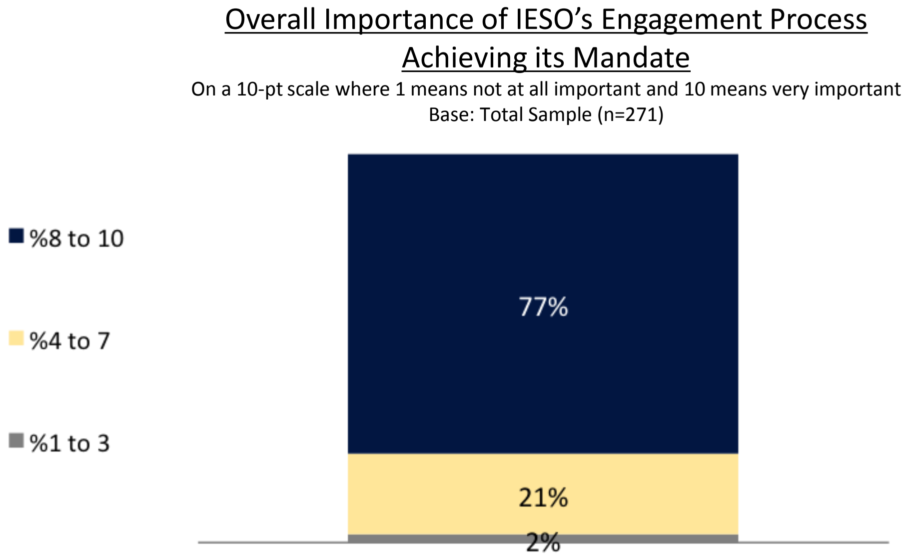
*NOTE: Extremely small sample size, should be interpreted as directional only.
1. To begin, how favourable is your opinion of the IESO's as an organization? Please use a 10-point scale where 1 means not at all favourable and 10 means very favourable. **CHECK 1 ONLY**

IESO's Engagement Process

How relevant is this initiative according to stakeholder business/sector needs? And, how satisfied are stakeholders with the process overall?

Importance of the Initiative's Success

- Over three quarters believe the success of the IESO's Engagement Process is very important in allowing the IESO to be effective, a finding consistent across each target stakeholder group.



	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
%8 to 10	82	74	50	78	83

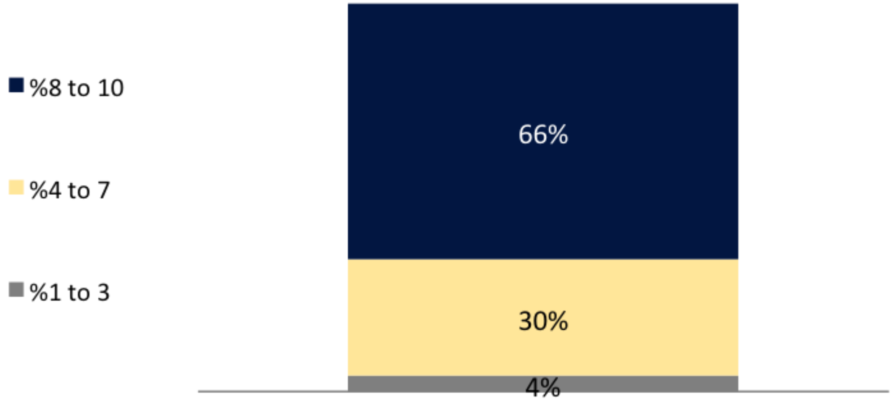
*NOTE: Extremely small sample size, should be interpreted as directional only.
5a. How important is the engagement process to the IESO achieving its overall mandate/objectives? Please provide a rating on a 10-point scale where 1 means not at all important and 10 means very important. CHECK ONE ONLY

Initiative's Relevance

- As participants, over two thirds believe that the current engagement process is relevant to their business/sector needs.
  - Large Consumers believe the process is slightly less relevant to their business than other groups, with generators and distributors most supportive.

Overall Relevance of the IESO's Engagement Process
To Business Sector/Needs

On a 10-pt scale where 1 means not at all relevant and 10 means very relevant
Base: Total Sample (n=271)



	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
%8 to 10	71	72	50	54	64

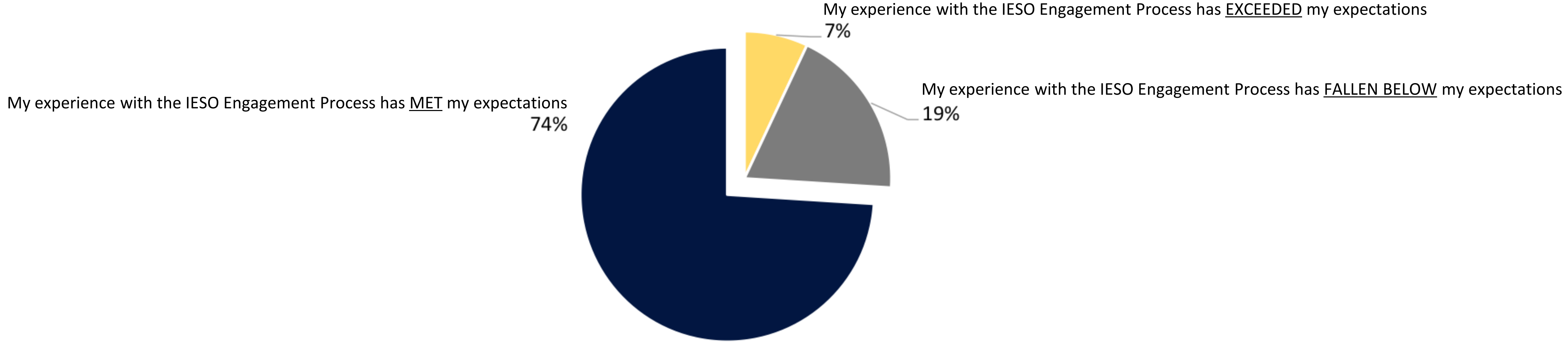
*NOTE: Extremely small sample size, should be interpreted as directional only.
7. And, as a participant, how relevant has the IESO's engagement process been to your business or sector needs? Please consider all of your interactions with the IESO and the various communication channels, programs and initiatives you have engaged with in your answer. Please provide a rating on a 10-point scale where 1 means their processes have not been relevant at all and 10 means they are very relevant. **CHECK ONE ONLY**

Stakeholder Expectations: Engagement Process

- The majority of stakeholders feel that the Engagement Process has met their expectations, however less than 10% report that the process has exceeded their expectations. 1 in 5 believe it has fallen below expectations.
  - These results are consistent across the target stakeholder groups.

Incidence of IESO Exceeding/Meeting & Falling Short of Stakeholder Expectations Based on Their Experience with the Engagement Process

Base: Total Sample (n=271)



	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
% EXCEEDED Expectations	8	7	-	3	11
% MET Expectations	73	78	79	70	71
% FALLEN BELOW Expectations	19	15	21	27	18

*NOTE: Extremely small sample size, should be interpreted as directional only.

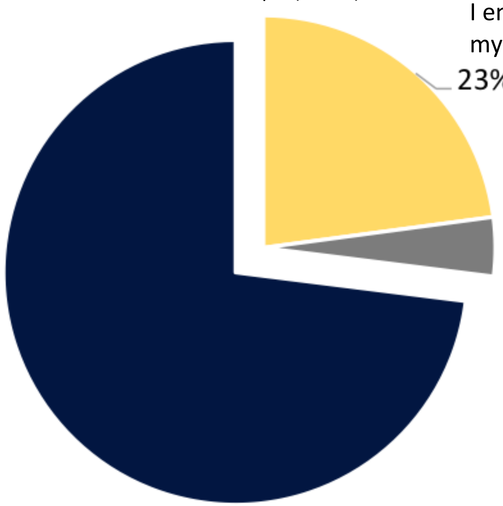
11. Which of the following statements best reflects your experience with the IESO's engagement process overall? CHECK ONE ONLY

Approach to Engagement

- Nearly all stakeholders (96%) have personal interests driving their participation in the process. However, the bulk of those claim they are also interested in learning about the needs of other participants.
  - 'Other' Interested Stakeholders are most likely to engage with the process for both reasons.

Approach to the IESO's Stakeholder Engagement Process

Base: Total Sample (n=271)



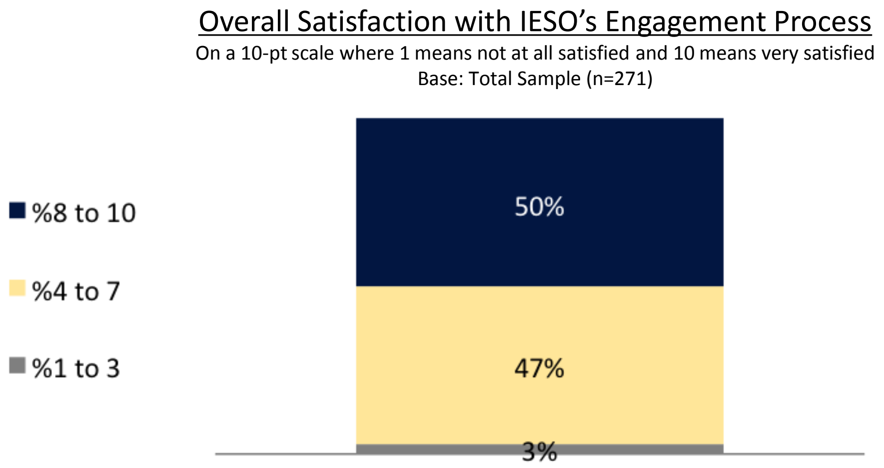
	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
Engage with the process to BOTH advance my needs and learn about the needs of others	69	74	64	54	89
Engage with the process primarily to advance my business needs	29	22	29	41	$\boxed{6}$
Engage with the process to learn about the needs of all others	2	4	7	5	5

*NOTE: Extremely small sample size, should be interpreted as directional only.

5b. Which of the following best reflects your approach to the IESO's engagement process?

Satisfaction with Engagement Process

- Satisfaction with IESO's engagement process is relatively moderate, revealing room for improvement on this metric.



Satisfaction with Engagement Process	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
%8 to 10	55	52	36	43	49
%4 to 7	44	44	64	51	46
%1 to 3	2	4	-	5	5

6a. As a participant, how satisfied are you with the IESO's engagement process?

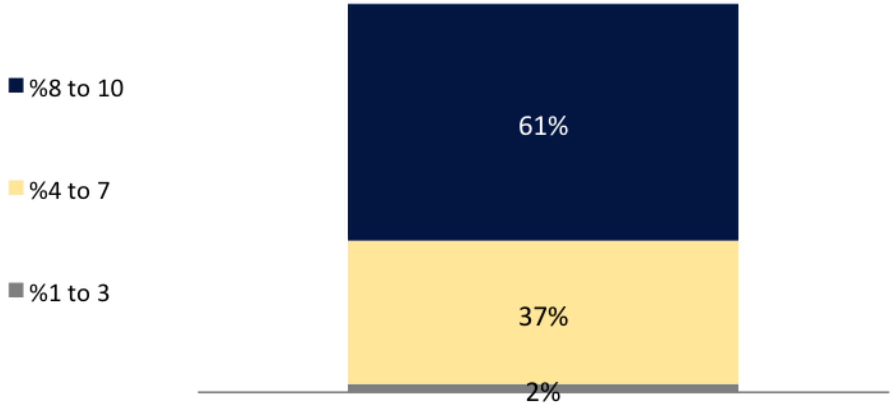
Perceived Commitment

- Two thirds of stakeholders believe that the staff interactions they have experienced very much reflect an organization that is committed to the Engagement Process.

Level of Perceived Commitment to IESO Engagement Process Based on Interactions with IESO Staff

On a 10-pt scale where 1 means the IESO's commitment is not at all reflected and 10 means the IESO's commitment is very much reflected

Base: Total Sample (n=271)



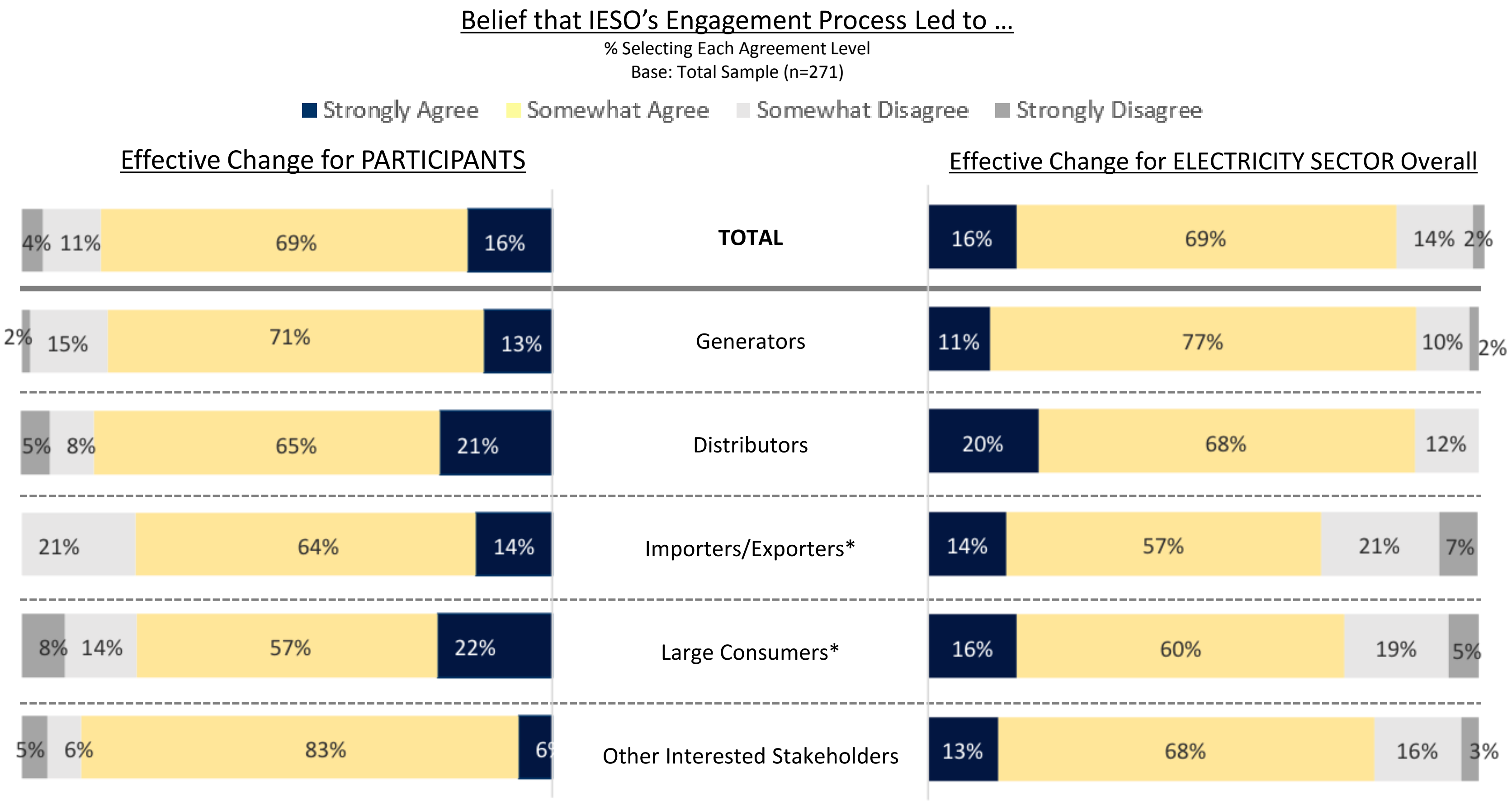
	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
%8 to 10	58	63	50	60	65

*NOTE: Extremely small sample size, should be interpreted as directional only.

10. How well is the IESO's commitment to the engagement process reflected in the staff interactions you have had? Please provide a rating on a 10-point where 1 means this commitment has not at all been reflected and 10 means the commitment has been reflected very well.

Perceived Impact of Process

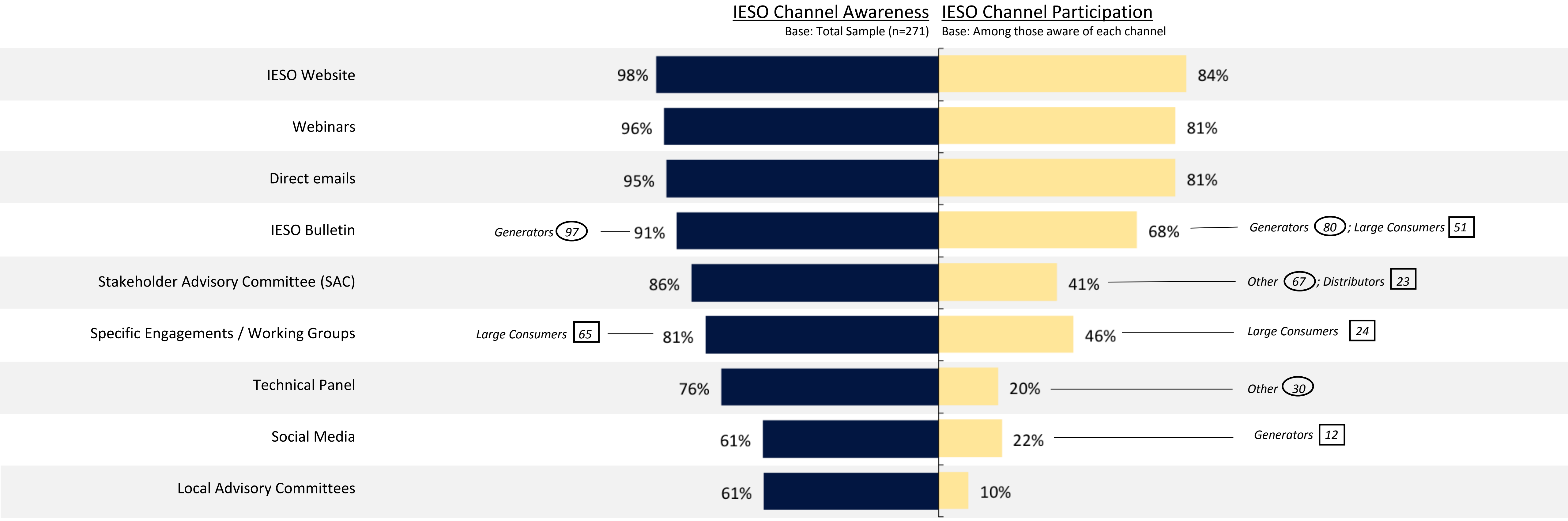
- Despite lukewarm satisfaction scores, the vast majority of stakeholders agree to some degree that the IESO's Engagement Process has enabled effective change both for individual participants and for the electricity sector overall.



*NOTE: Extremely small sample size, should be interpreted as directional only.
14. To what extent do you agree or disagree with the following statements? CHECK ONE ONLY PER STATEMENT

Channel Engagement

- IESO's online channels – the organization's website, webinars and direct emails generate the highest awareness and are by far the most used.



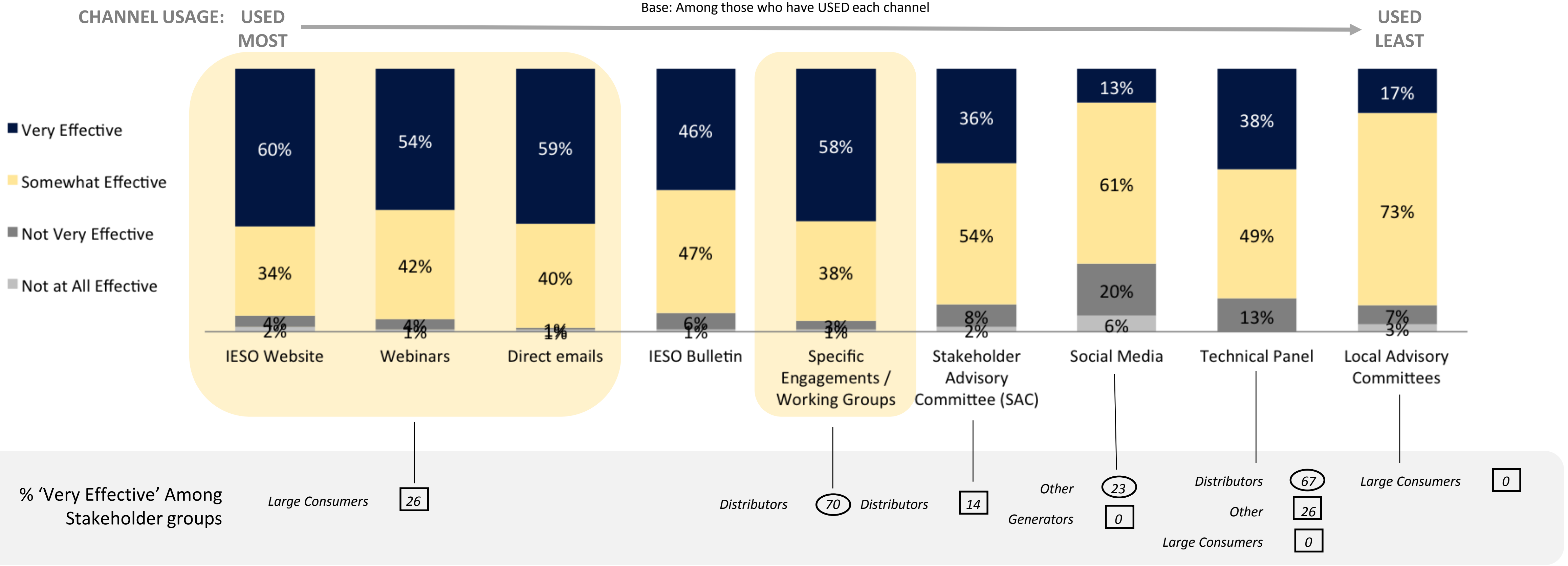
4a. I'm going to read you a list of possible channels and programs that the IESO uses to enable engagement with stakeholders like yourself. Please indicate which of the following channels/programs you have heard of before today. READ LIST, CHECK ALL THAT APPLY
4b. FOR EACH CHANNEL MENTIONED AT 4a: Which of these channels/programs have you used and/or participated in? READ LIST, CHECK ALL THAT APPLY

Channel Effectiveness

- Most channels are perceived as being at least somewhat effective by the majority of stakeholders sampled.
  - Additionally, there is a clear correlation between usage and effectiveness, given that the top three most used online channels are also perceived as being the most effective.
  - Specific Engagements/Working Groups, used by less than half of stakeholders are perceived as being highly effective.

Channel Effectiveness

Base: Among those who have USED each channel



4c. FOR EACH CHANNEL USED AT 4b ASK: How effective are each of the following channels/programs in enabling you to engage with the IESO in a relevant manner? Please provide a rating on the following scale - 'very', 'somewhat', 'not very' or 'not at all' effective for each channel/program listed. READ LIST, CHECK ALL THAT APPLY

IESO's Public Value

Do stakeholders believe that the IESO is delivering public value?

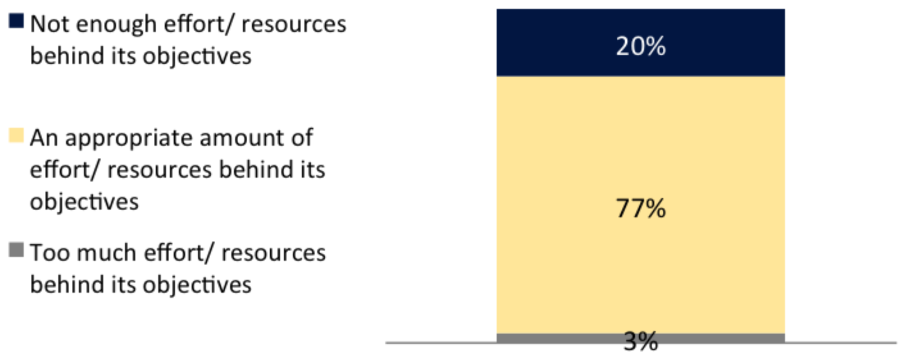
Public Value Composite Score

- Over three quarters of stakeholders believe that the IESO is putting an appropriate amount of resources and effort behind its objectives as an organization.

Public Value Composite Score

Based on a composite score of all public value objectives shown to stakeholders

Base: Total Sample (n=271)



%8 to 10	Generators	Distributors	Importers/ Exporters	Large Consumers	Other Interested Stakeholders
Base n=	62	95	14*	37*	63
Not enough effort/ resources behind its objectives	18	16	22	25	22
An appropriate amount of effort/ resources behind its objectives	78	80	74	73	75
Too much effort/ resources behind its objectives	4	4	4	2	3

3b. Please identify how you feel about the IESO's current effort and resource allocation against each of the following objectives. READ LIST, CHECK ONE PER STATEMENT

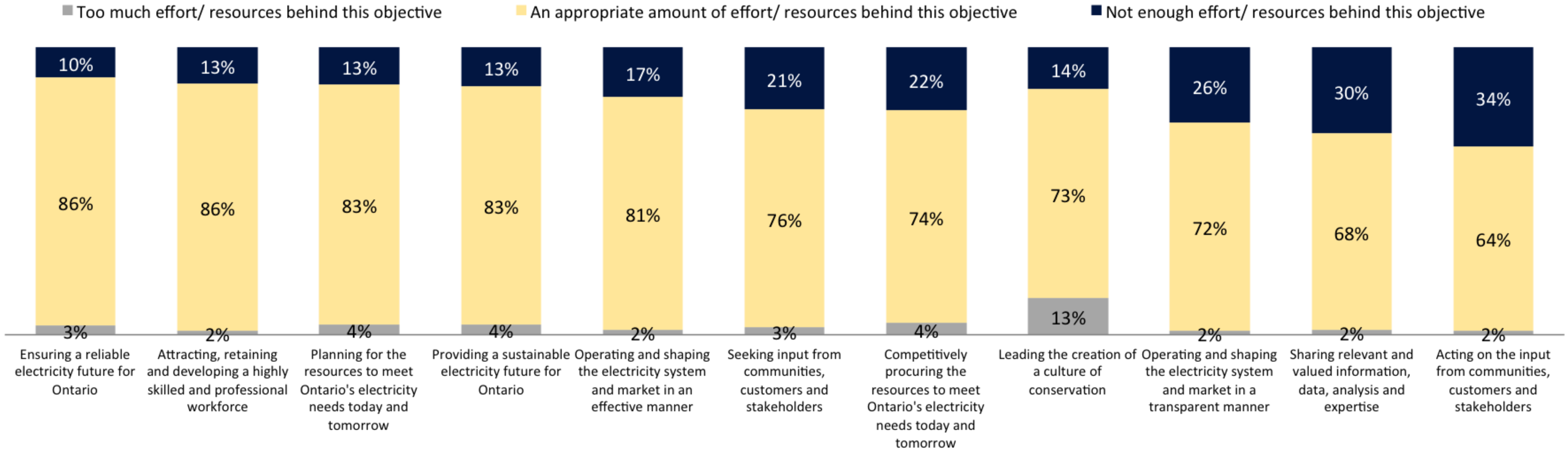
Public Value Assessment

- The majority of stakeholders believe the IESO is putting an appropriate amount of effort/ resources behind each objective. However, ratings are lowest for acting on input and sharing valued information.

Public Value Assessment: Effort/Resource Perceptions for Each IESO Objective

The IESO is putting …

Base: Total Sample (n=271)



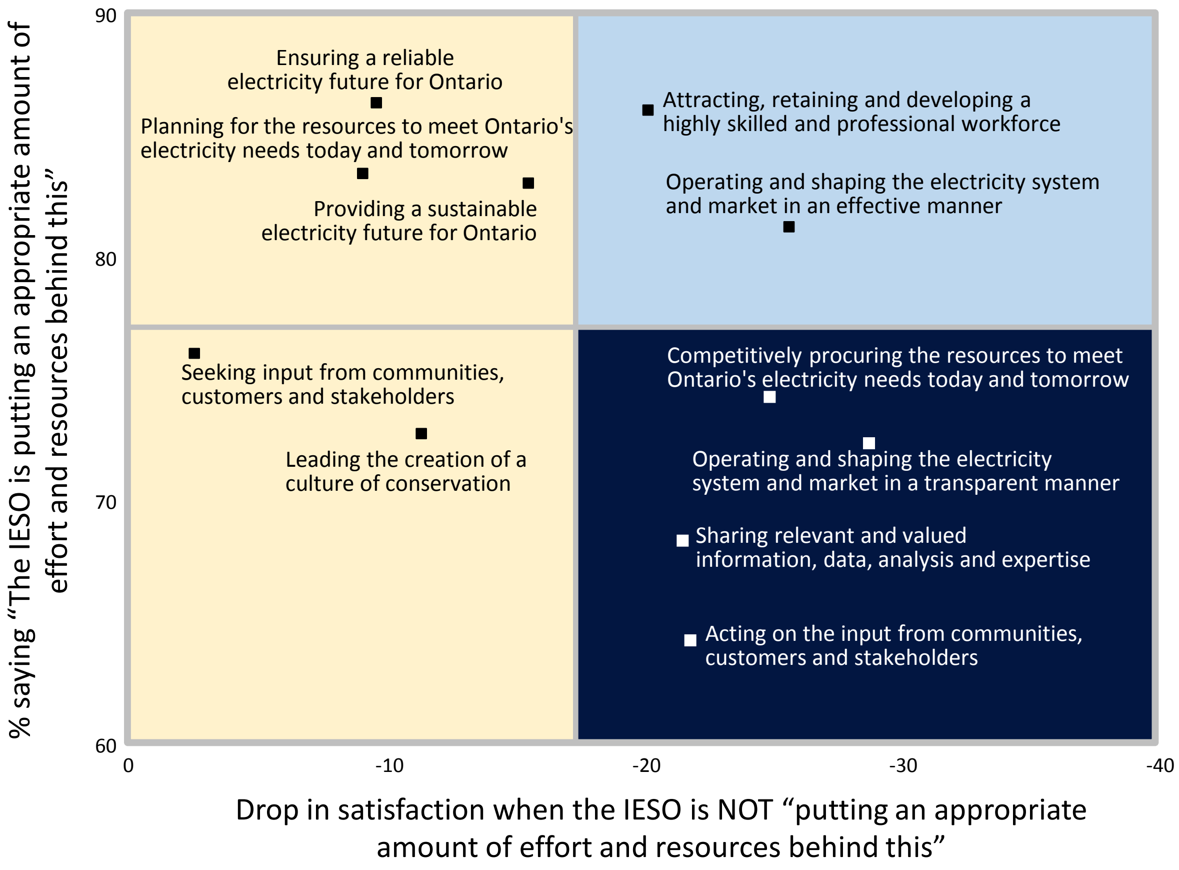
3b. Please identify how you feel about the IESO's current effort and resource allocation against each of the following objectives. READ LIST, CHECK ONE PER STATEMENT

Prioritizing Public Value Delivery

- The map below identifies the most critical value objectives for the IESO according to stakeholders.

READING THE MAP:

- The higher up the Y axes, the higher the % of stakeholders who believe IESO is putting the appropriate amount of effort into this area.
- The further to the right on the X axes, the greater the impact (loss) in satisfaction should the IESO not put the appropriate amount of effort into this area/objective.



AREAS TO INVEST:

Fewer stakeholders feel the IESO is putting the appropriate amount of resources into these objectives and, these objectives could have the greatest impact on overall satisfaction

3a. Please indicate how well you feel the IESO is currently performing on each of the following objectives. Please provide a rating on a 10-point scale where 1 means the IESO is performing poorly on that objective and 10 means they are performing very well on that objective. RECORD ONE RATING PER OBJECTIVE
3b. Please identify how you feel about the IESO's current effort and resource allocation against each of the following objectives. READ LIST, CHECK ONE PER STATEMENT

The Relationship Between Satisfaction, Engagement & Public Value Scores

- There is a strong relationship between each of the three scores and very few stakeholders are highly satisfied with the organization if they are not satisfied with the overall engagement process and/or believe that the IESO is delivering in public value.
- 31% report high satisfaction with the IESO, high satisfaction with engagement and a high rating for the IESO devoting the right amount of resources to objectives.

SCORE A = HIGH OVERALL SATISFACTION SCORE

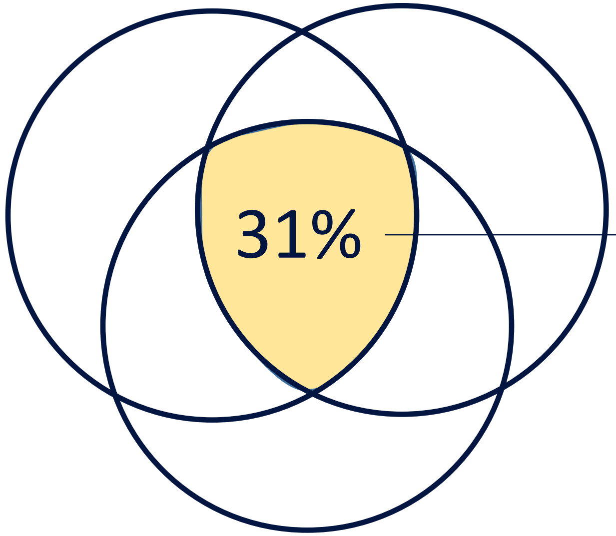
•(Stakeholders who rated their overall satisfaction the IESO's performance an 8 to 10 on a 10-point scale)

SCORE B = HIGH ENGAGEMENT PROCESS SATISFACTION SCORE

•(Stakeholders who rated their satisfaction with the stakeholder engagement process an 8 to 10 on a 10-point scale)

SCORE C = HIGH PUBLIC VALUE COMPOSITE SCORE

•(Stakeholders who believe that the IESO is putting an appropriate amount of effort/resources behind their objectives)



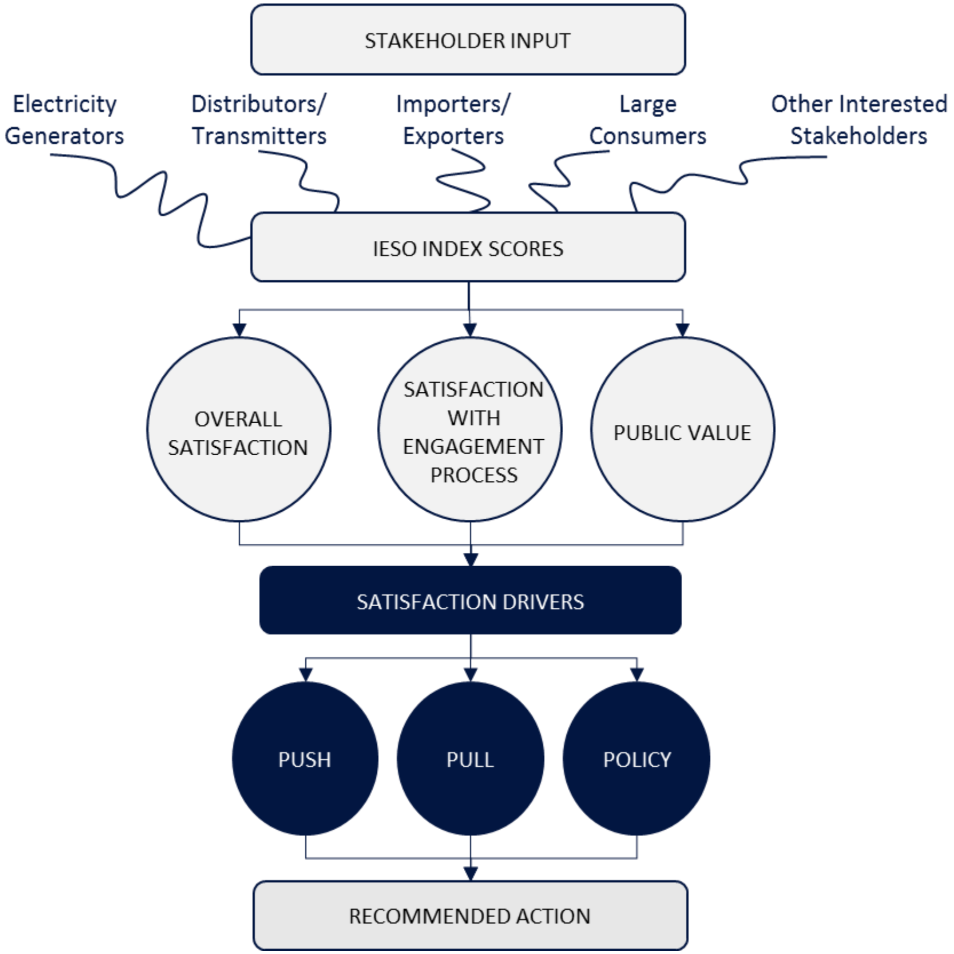
A + B + C

Most frequently, stakeholders give high scores across each metric - identifying the critical need to deliver on all three areas.

NOTE: For detailed scores at each intersection, please see Appendix l.

2a. Based on your experience, how satisfied are you with the IESO's overall performance? Please use a 10-point scale where 1 means you are not at all satisfied and 10 means you are very satisfied with the IESO.
3b. Please identify how you feel about the IESO's current effort and resource allocation against each of the following objectives. READ LIST, CHECK ONE PER STATEMENT
6a. As a participant, how satisfied are you with the IESO's engagement process?

Satisfaction Drivers



Approach: Factor Analysis & Driver Analysis

- Our key driver analysis is based on a two-phased approach:

  1. FACTOR ANALYSIS: Which was used to determine the attributes from each of the three key performance questions that grouped together into common themes.
  2. KEY DRIVER ANALYSIS: Which was used to determine the key drivers of satisfaction.

- The flow chart below details the three key analytical steps involved in this two-phased approach:

STEP 1

IDENTIFY THE VARIABLES:

1.DEPENDENT VARIABLES:
- Overall Satisfaction with IESO
- Overall Satisfaction with IESO's Engagement Process

2.INDEPENDENT VARIABLES: (3 Tiers)
- IESO's Mission/Vision Corporate Objectives (Q3a)
- Engagement Process Performance Areas (Q8)
- Personality Associations (Q9)

STEP 2

IDENTIFY THEMES:

•FACTOR ANALYSIS was then used to determine which independent variables (attributes sourced from the 3 questions listed above – Q3a/8/9) could be grouped together into common themes.

•This analysis resulted in 3 larger themes, each with its own list of drivers

STEP 3

IDENTIFY KEY DRIVERS:

•Derived importance was then used to determine the most important drivers to satisfaction within each larger theme.

•From here, we are able to look at the IESO's performance on each theme (and driver within it) to understand why satisfaction scores are what they are – overall and by each target group.

Factor Analysis Overview: Themes

(Independent Variables)

- Our factor analysis found three overall themes across attributes:

PUSH

What the IESO sends out to its stakeholders

(i.e. communications, information, innovation ideas etc.)

PULL

What the IESO takes in from its stakeholders

(general feedback, unique challenges & recommendations toward action)

POLICY

How the IESO positions itself to its stakeholders within the electricity sector more broadly

(i.e. conservation, system reliability, resource management etc.).

The following slide reveals the variables/drivers included in each group

Factor Analysis Overview: Drivers By Theme

(Independent Variables)

DRIVER TIERS:	1 PUSH	2 PULL	3 POLICY
CORPORATE MISSION & VISION (Q3a)	• Sharing relevant and valued information, data, analysis and expertise • Operating and shaping the electricity system and market in a transparent manner	• Seeking input from communities, customers and stakeholders • Acting on the input from communities, customers and stakeholders	• Ensuring a reliable electricity future for Ontario • Leading the creation of a culture of conservation • Providing a sustainable electricity future for Ontario • Attracting, retaining and developing a highly skilled and professional workforce • Planning for the resources to meet Ontario's electricity needs today and tomorrow • Competitively procuring the resources to meet Ontario's electricity needs today and tomorrow • Operating and shaping the electricity system and market in an effective manner
ENGAGEMENT PROCESS PRINCIPALS (Q8)	• Ensuring staff accessibility to you • Effectively communicating with you • Providing relevant/ meaningful information to you • Communicating with you in a timely manner • Clearly communicating outcomes • Offering you insight on market electricity issues • Responding to needs in a timely manner	• Provide effective facilitation • Analyzing and creating opportunities for stakeholder engagement • Ensuring inclusive representation of stakeholder needs • Ensuring adequate representation of stakeholder needs	•Operating a reliable system •Enabling innovation in the electricity sector
PERSONALITY ATTRIBUTES (Q9)	• Respectful • Honest • Trustworthy • Sincere • Timely • Transparent	• Inclusive • Fair • Balanced • Understanding • Consultative • Open • Flexible	• Reliable • Sustainable • Consistent • Predictable

*41 Variables total

Driver Performance

How is the IESO performing on the key drivers identified?

Push Performance

- The IESO's performance varies across the 'Push' drivers, and is strongest for being a 'respectful' organization.
- Performance ratings are much lower when the focus shifts to transparency.

Perceived Performance On Each Area

% Rating 8 to 10 on a 10-pt scale where 1 means performs poorly and 10 means performs very well on each area
Base: Total Sample (n=271)

	Total	Generators n=62	Distributors n=95	Importers/ Exporters n=14*	Large Consumers n=37*	Other Interested Stakeholders n=63
Respectful	76%	79%	78%	93%	68%	70%
Honest	59%	61%	64%	50%	54%	56%
Trustworthy	58%	58%	64%	57%	46%	54%
Ensuring staff accessibility to you	54%	60%	55%	43%	54%	48%
Effectively communicating with you	52%	52%	58%	50%	46%	48%
Providing relevant / meaningful information to you	51%	47%	62%	36%	43%	48%
Sincere	51%	50%	56%	57%	46%	48%
Communicating with you in a timely manner	51%	52%	54%	57%	43%	49%
Timely	47%	44%	47%	57%	51%	43%
Responding to needs in a timely manner	46%	52%	47%	43%	41%	43%
Sharing information, analysis and expertise	44%	48%	46%	50%	30%	41%
Clearly communicating outcomes	41%	50%	44%	43%	32%	32%
Offering you insight on market electricity issues	40%	39%	40%	36%	35%	43%
Transparent	40%	37%	51%	36%	35%	29%
Transparently operating & shaping the electricity system and market	39%	42%	43%	21%	24%	41%

*NOTE: Extremely small sample size, should be interpreted as directional only.
3a. Please indicate how well you feel the IESO is currently performing on each of the following objectives. Please provide a rating on a 10pt scale where 1 means poorly and 10 means performing very well.
8. How well has the organization performed on each of the following areas?
9. Based on the experience you have had with the IESO stakeholder engagement process, how well do you feel the IESO reflects the following values?

Pull Performance

- The IESO's performance is more moderate across the list of 'Pull' drivers.
- Strongest ratings centre around inclusiveness and facilitating input, however fall short on flexibility and action.

Perceived Performance On Each Area

% Rating 8 to 10 on a 10-pt scale where 1 means performs poorly and 10 means performs very well on each area
Base: Total Sample (n=271)

	Total	Generators n=62	Distributors n=95	Importers/ Exporters n=14*	Large Consumers n=37*	Other Interested Stakeholders n=63
Inclusive	51%	50%	56%	64%	41%	48%
Providing effective facilitation	50%	55%	60%	50%	35%	40%
Seeking input from all stakeholders	48%	53%	53%	36%	41%	44%
Fair	47%	45%	61%	43%	38%	35%
Balanced	45%	45%	56%	36%	46%	32%
Analysing and creating opportunities for stakeholder engagement	44%	40%	51%	29%	35%	44%
Understanding	43%	44%	51%	50%	38%	33%
Ensuring inclusive representation of stakeholder needs	42%	37%	44%	43%	35%	46%
Ensuring adequate representation of stakeholder needs	40%	39%	48%	29%	32%	37%
Consultative	40%	36%	54%	29%	32%	32%
Open	40%	44%	46%	50%	35%	25%
Acting on stakeholder input	30%	32%	28%	29%	32%	30%
Flexible	29%	31%	37%	43%	16%	19%

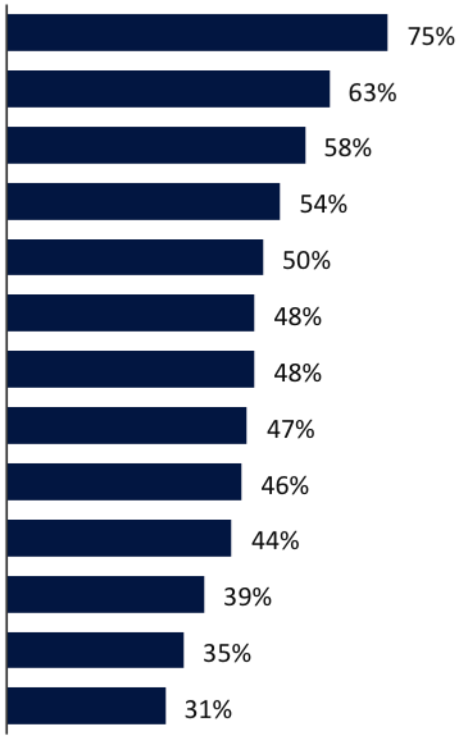
*NOTE: Extremely small sample size, should be interpreted as directional only.
3a. Please indicate how well you feel the IESO is currently performing on each of the following objectives. Please provide a rating on a 10pt scale where 1 means poorly and 10 means performing very well.
8. How well has the organization performed on each of the following areas?
9. Based on the experience you have had with the IESO stakeholder engagement process, how well do you feel the IESO reflects the following values?

Policy Performance

- In terms of the IESO's performance on drivers related to 'Policy' – the organization is seen first and foremost as reliable.
- To a much lesser degree, the IESO is perceived to be enabling innovation and competitively procuring resources.

Perceived Performance On Each Area

% Rating 8 to 10 on a 10-pt scale where 1 means performs poorly and 10 means performs very well on each area
Base: Total Sample (n=271)



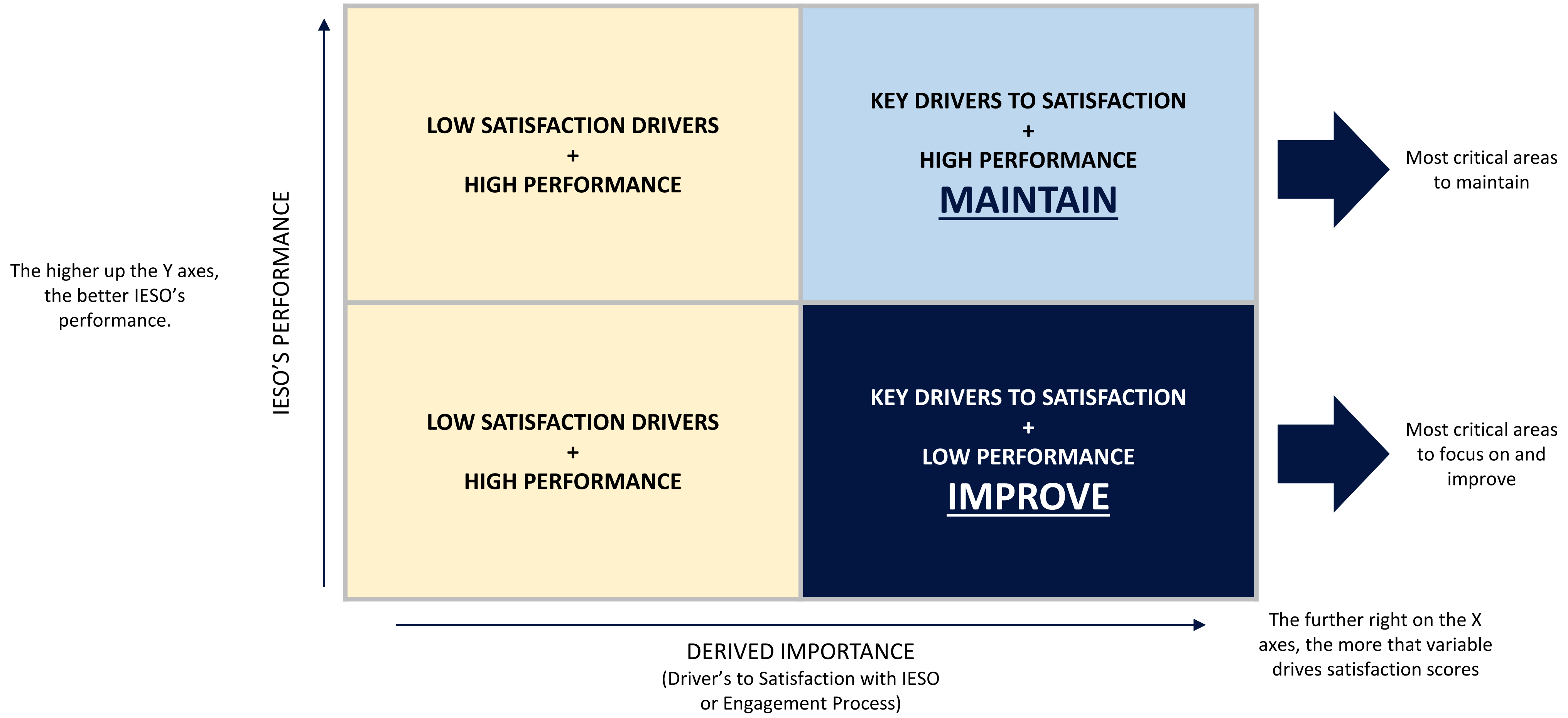
	Total	Generators n=62	Distributors n=95	Importers/ Exporters n=14*	Large Consumers n=37*	Other Interested Stakeholders n=63
Operating a reliable system	75%	81%	76%	50%	60%	81%
Reliable	63%	66%	67%	64%	54%	59%
Ensuring a reliable electricity future	58%	63%	57%	43%	51%	64%
Sustainable	54%	60%	60%	$\boxed{29\%}$	51%	44%
Consistent	50%	53%	54%	71%	49%	38%
Leading the creation of a culture of conservation	48%	48%	56%	43%	41%	43%
Predictable	48%	53%	57%	29%	43%	38%
Providing a sustainable electricity future for Ontario	47%	53%	51%	$\boxed{21\%}$	$\boxed{24\%}$	54%
Highly skilled and professional workforce	46%	50%	54%	43%	32%	38%
Planning for the resources to meet electricity needs	44%	47%	46%	29%	38%	44%
Effectively operating & shaping the electricity system and market	39%	40%	42%	21%	35%	38%
Enabling innovation in the electricity sector	35%	34%	43%	36%	30%	25%
Competitively procurement of resources	31%	34%	34%	21%	22%	32%

*NOTE: Extremely small sample size, should be interpreted as directional only.
3a. Please indicate how well you feel the IESO is currently performing on each of the following objectives. Please provide a rating on a 10pt scale where 1 means poorly and 10 means performing very well.
8. How well has the organization performed on each of the following areas?
9. Based on the experience you have had with the IESO stakeholder engagement process, how well do you feel the IESO reflects the following values?

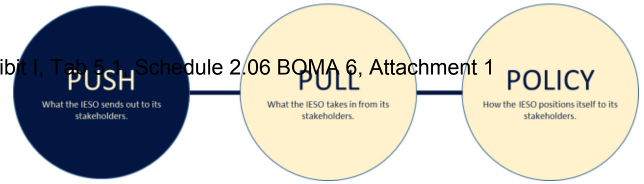
Driver Analysis

What impact does performance have on IESO satisfaction scores?

Understanding Our Performance Matrix

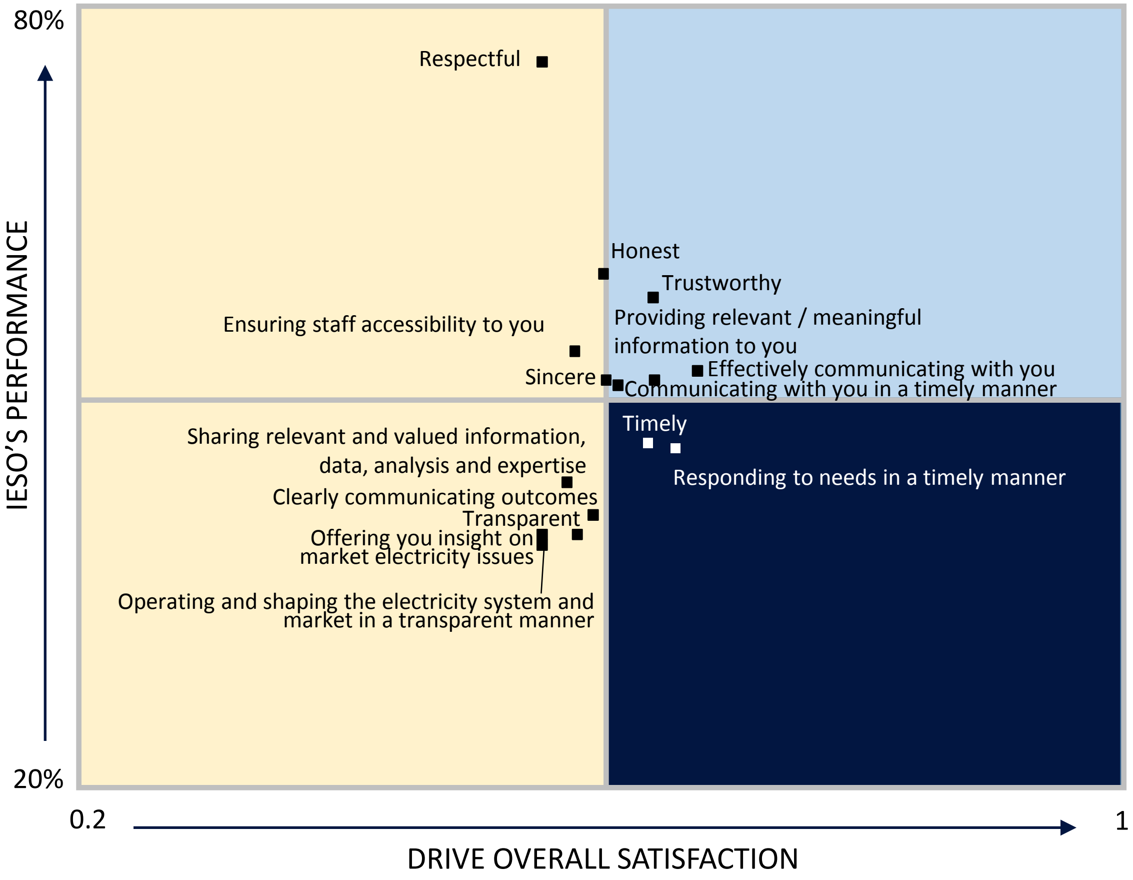


‘PUSH’: Performance

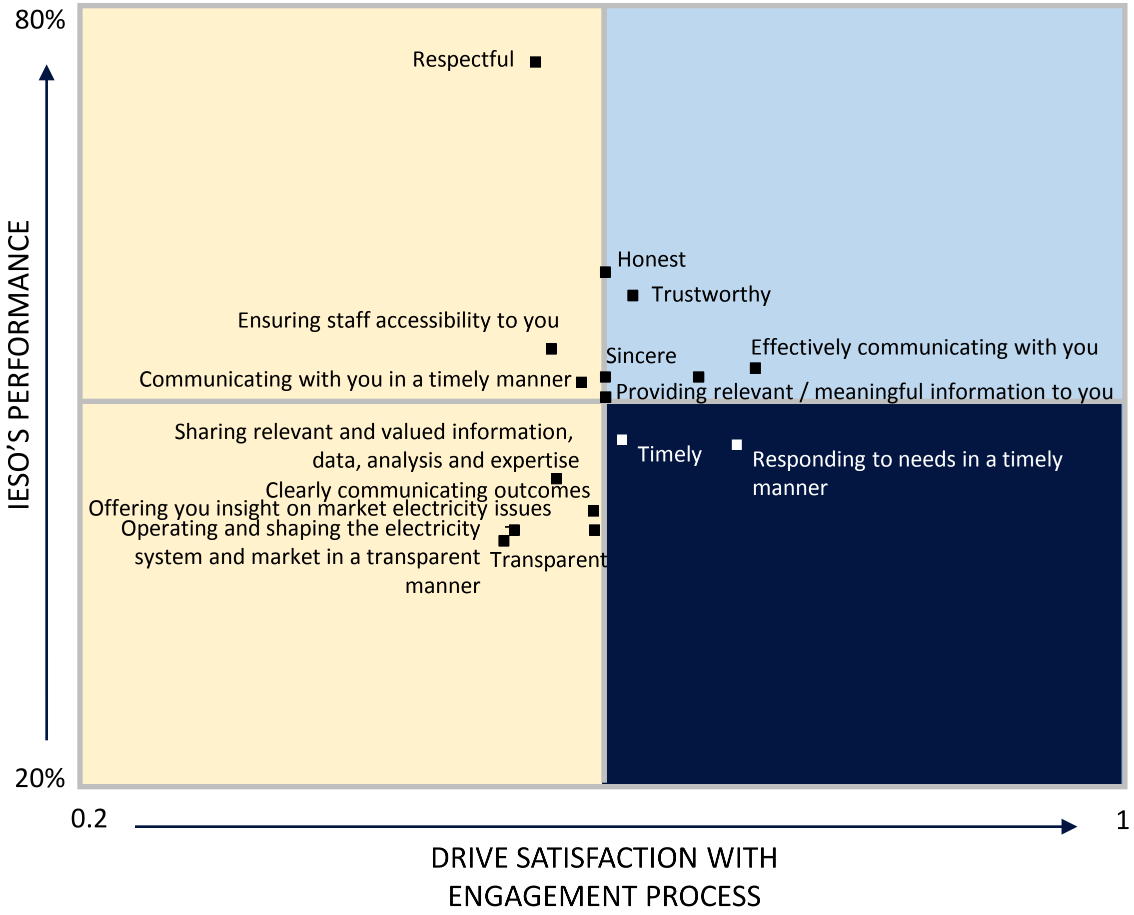


- Given their strong relationship, the key drivers to maintain and invest in for the ‘Push’ category are aligned across both satisfaction indeces. The IESO should continue to maintain it’s efforts in honest, trustworthy and effective communication but focus on improving timely responsiveness.

IESO’s PERFORMANCE vs. OVERALL SATISFACTION



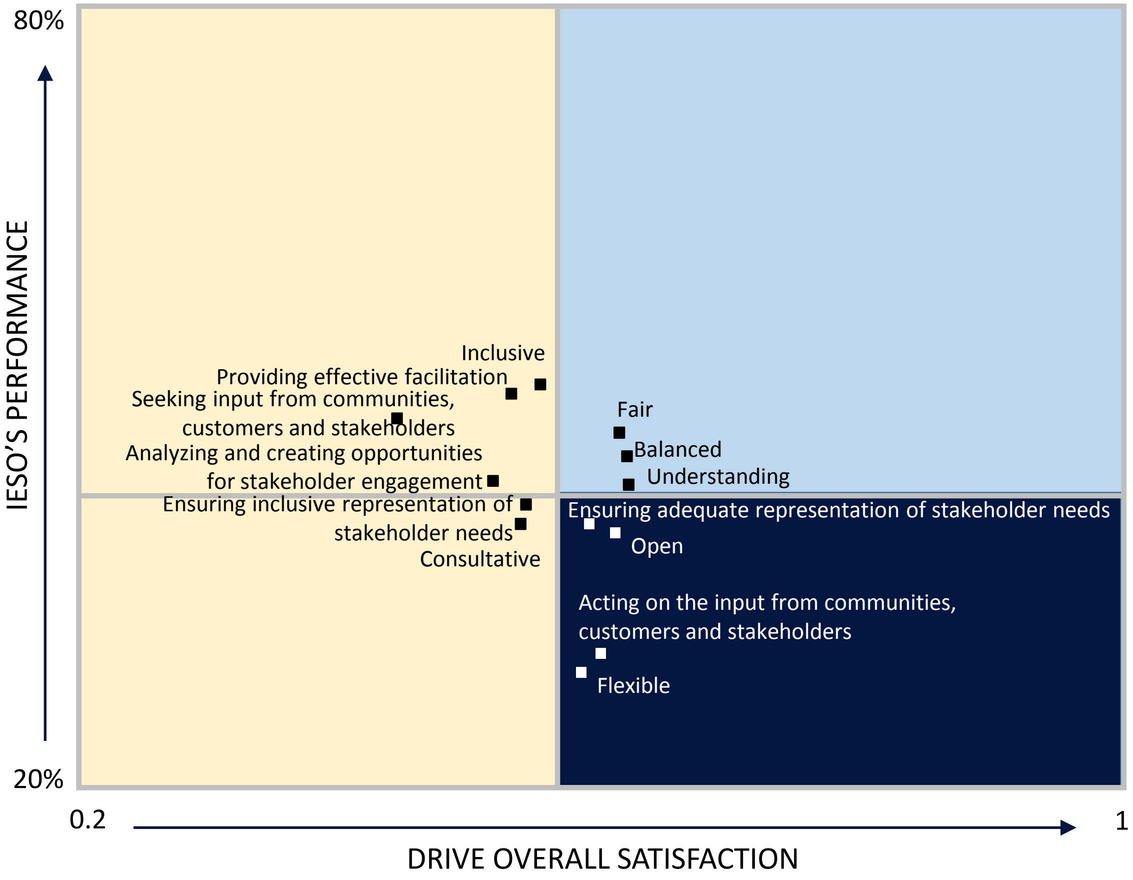
IESO’s PERFORMANCE vs. SATISFACTION WITH ENGAGEMENT PROCESS



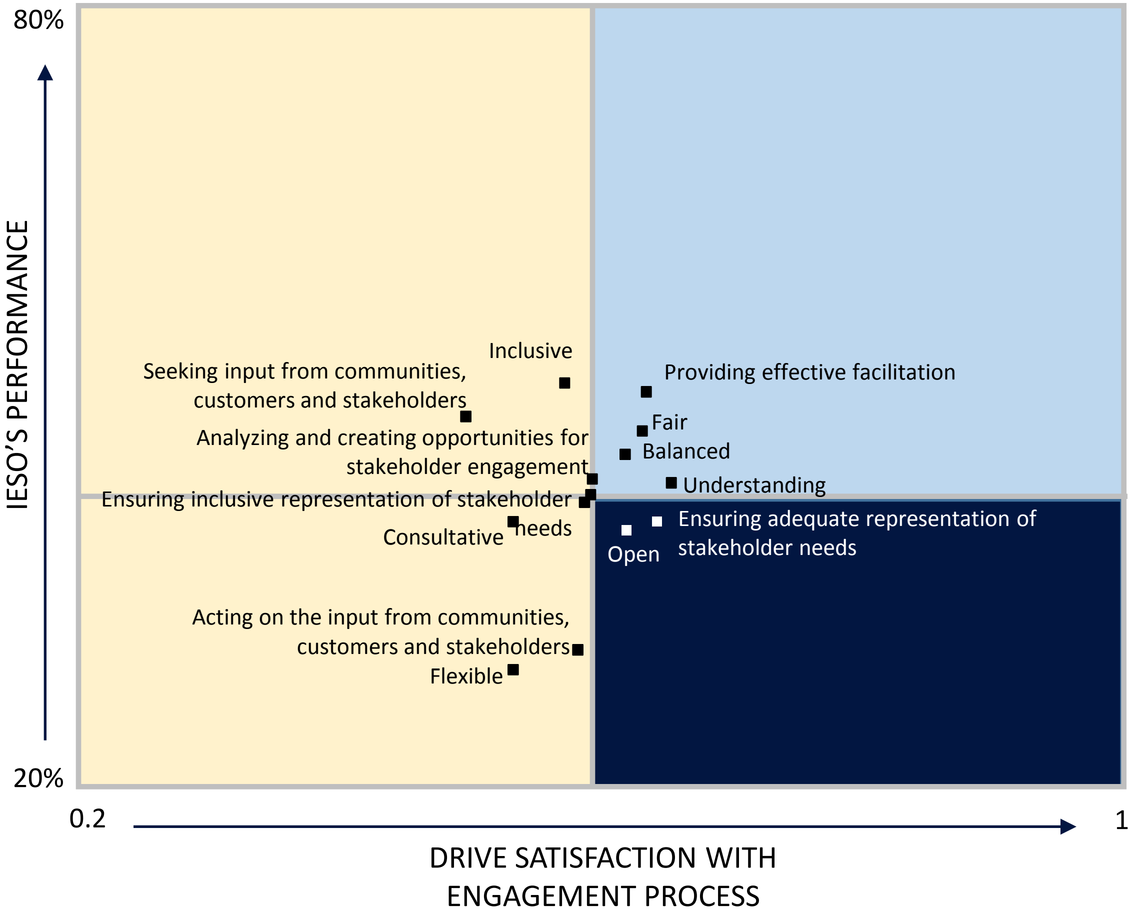
‘PULL’: Performance

- Similarly, in the ‘Pull’ category drivers, efforts to improve performance in ‘openness’ and ‘ensuring adequate representation of needs’ will increase satisfaction both overall and with the engagement process specifically. Efforts should also focus on acting on input and flexibility in actions to increase overall satisfaction.

IESO’s PERFORMANCE vs. OVERALL SATISFACTION



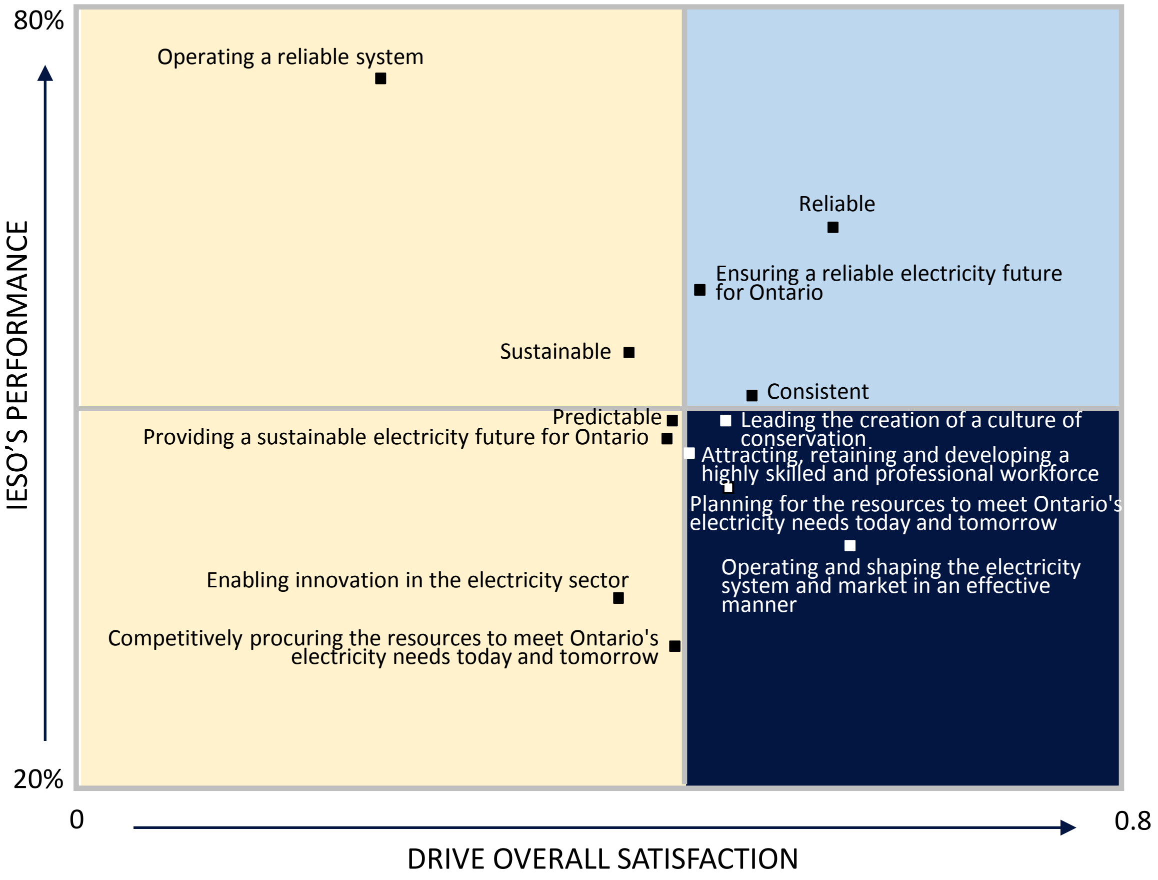
IESO’s PERFORMANCE vs. SATISFACTION WITH ENGAGEMENT PROCESS



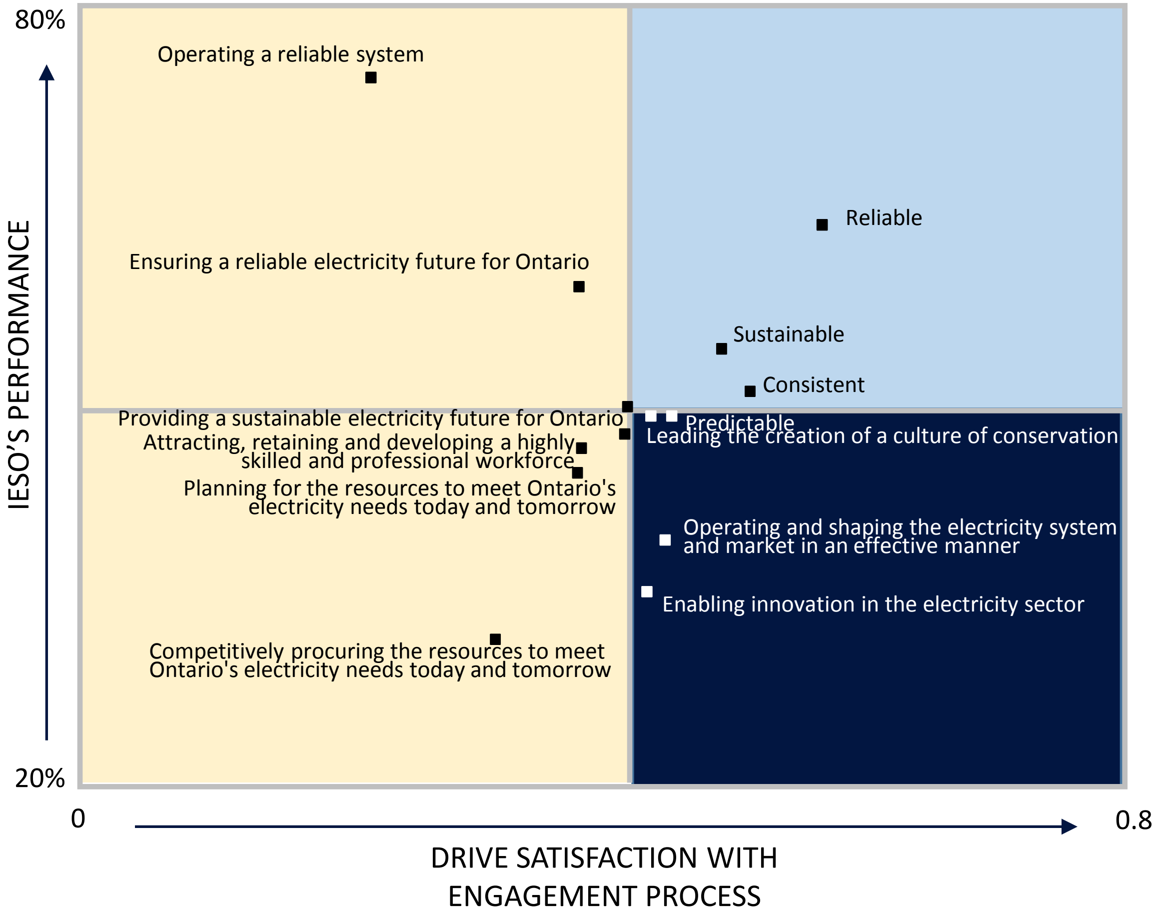
'POLICY': Performance

- The IESO should maintain its status as a reliable and consistent organization to maintain strong levels of satisfaction on both metrics among stakeholders. 'Policy' drivers to improve on centre around leadership, planning and innovation.

IESO's PERFORMANCE vs. OVERALL SATISFACTION

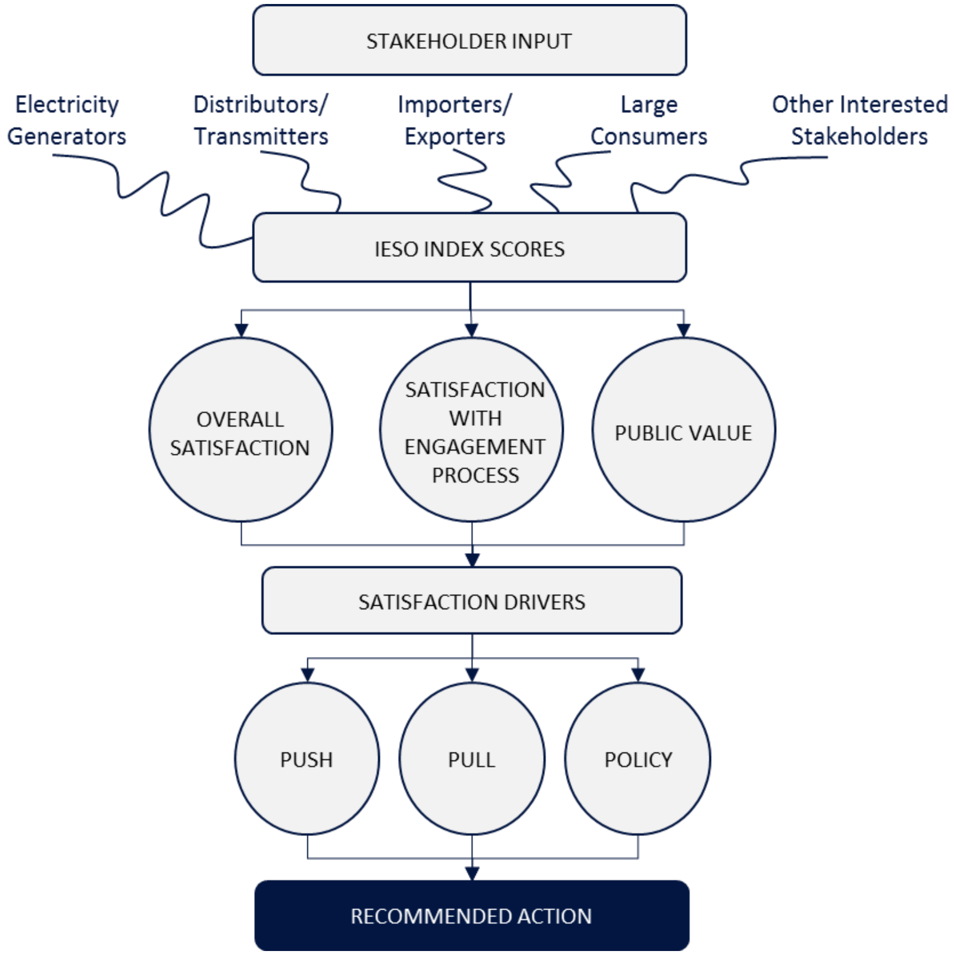


IESO's PERFORMANCE vs. SATISFACTION WITH ENGAGEMENT PROCESS



Recommendations

In which areas should IESO focus its actions?



Key Focus Areas: Overall

DRIVER TIERS:	1 PUSH	2 PULL	3 POLICY
CORPORATE MISSION & VISION (Q3a)	• Sharing relevant and valued information, data, analysis and expertise • Operating and shaping the electricity system and market in a transparent manner	• Seeking input from communities, customers and stakeholders • **Acting on the input from communities, customers and stakeholders**	• Ensuring a reliable electricity future for Ontario • **Leading the creation of a culture of conservation** • Providing a sustainable electricity future for Ontario • **Attracting, retaining and developing a highly skilled and professional workforce** • **Planning for the resources to meet Ontario's electricity needs today and tomorrow** • Competitively procuring the resources to meet Ontario's electricity needs today and tomorrow • **Operating and shaping the electricity system and market in an effective manner**
ENGAGEMENT PROCESS PRINCIPALS (Q8)	• Ensuring staff accessibility to you • Effectively communicating with you • Providing relevant/ meaningful information to you • Communicating with you in a timely manner • Clearly communicating outcomes • Offering you insight on market electricity issues • **Responding to needs in a timely manner**	• Provide effective facilitation • Analyzing and creating opportunities for stakeholder engagement • **Ensuring inclusive representation of stakeholder needs** • **Ensuring adequate representation of stakeholder needs**	•Operating a reliable system •**Enabling innovation in the electricity sector**
PERSONALITY ATTRIBUTES (Q9)	• Respectful • Honest • Trustworthy • Sincere • **Timely** • Transparent	• Inclusive • Fair • Balanced • Understanding • Consultative • **Open** • **Flexible**	• Reliable • Sustainable • Consistent • **Predictable**

RED= ACTION AREAS FOR BOTH OVERALL SATISFACTION & SATISFACTION WITH ENGAGEMENT PROCESS
PURPLE =ACTION AREAS FOR OVERALL SATISFACTION
ORANGE=ACTION AREAS FOR ENGAGEMENT PROCESS

Key Focus Areas: By Stakeholder Group

READING THIS CHART: Indicates an area to invest in for the stakeholder group(s) identified **Generators** **Distributors** **Large Consumers** **Other Stakeholders**

DRIVER TIERS:	1 PUSH	2 PULL	3 POLICY
CORPORATE MISSION & VISION (Q3a)	• Sharing relevant and valued information, data, analysis and expertise • Operating and shaping the electricity system and market in a transparent manner	• Seeking input from communities, customers and stakeholders • Acting on the input from communities, customers and stakeholders	• Ensuring a reliable electricity future for Ontario • Leading the creation of a culture of conservation • Providing a sustainable electricity future for Ontario • Attracting, retaining and developing a highly skilled and professional workforce • Planning for the resources to meet Ontario's electricity needs today and tomorrow • Competitively procuring the resources to meet Ontario's electricity needs today and tomorrow • Operating and shaping the electricity system and market in an effective manner
ENGAGEMENT PROCESS PRINCIPALS (Q8)	• Ensuring staff accessibility to you • Effectively communicating with you • Providing relevant/ meaningful information to you • Communicating with you in a timely manner • Clearly communicating outcomes • Offering you insight on market electricity issues • Responding to needs in a timely manner	• Provide effective facilitation • Analyzing and creating opportunities for stakeholder engagement • Ensuring inclusive representation of stakeholder needs • Ensuring adequate representation of stakeholder needs	•Operating a reliable system •Enabling innovation in the electricity sector
PERSONALITY ATTRIBUTES (Q9)	• Respectful • Honest • Trustworthy • Sincere • Timely • Transparent	• Inclusive • Fair • Balanced • Understanding • Consultative • Open • Flexible	• Reliable • Sustainable • Consistent • Predictable

UNIQUE

(Attributes shown below are areas for investment that are unique to each stakeholder group)

Generators:
- Being fair in policy / rule-making decisions
- Being a trusted advisor
- Being predictable in its actions and decisions

Distributors:
- Being a partner in delivering conservation programs
- Being able to understand your customers' needs

Large Consumers:
- Balancing the various sector interests in its decision making
- Reflecting consumers in decision making

Other Stakeholders:
- Reflecting stakeholders in decision making
- Supporting the operations of your organization

Importer/Exporter sample size too small (n=14) to conduct this analysis.

NOTE: **For full drill-down analysis of each stakeholder group please see Appendix II.**

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BOMA INTERROGATORY 16

Issue 5.1

INTERROGATORY

Ref: ***Issue 5.1; Exhibit C, Tab 1, Schedule 1, Attachment 1; Elenchus Report***

(a) In the Scorecard, attached to the Elenchus Report, and attached to this IR (Appendix 1), and entitled "Proposed and Illustrative IESO Regulatory Scorecard" (and found at p7 of the Elenchus Report, being proposed by the IESO as the regulatory scorecard for 2017, and 2018); does the IESO support and endorse this Scorecard for use in this case?

(i) Is the IESO asking that the Board approve this Scorecard in this proceeding?

(ii) The Scorecard shown on p7 of the Elenchus Report does not have 2017, 2018 targets for many of the metrics. Does the IESO intend to set targets for these measures? If so, when?

(b) Please provide a copy of the 2017 IESO Internal Scorecard, unless the Internal Scorecard is the 10 key performance metrics addressed in the 2017-2019 Business Plan, at pp19-22.

(c)

(i) Please explain the difference between the purposes of a corporate scorecard and the purposes of a regulatory scorecard. Is it not the case that a regulated utility (whether an LDC or IESO) that does not score well on its internal "corporate" scorecard, that is, that it is not properly managed, or insufficiently or excessively resourced, will not perform well on its regulatory scorecard.

(ii) Do you agree that a manager's and the corporation's performance on its corporate scorecard is an important driver of executive/manager compensation, which is of interest to the OEB, and an important part of the revenue requirement?

(iii) Put another way, does the OEB not have the responsibility to assess the effectiveness and efficiency of the IESO, much of which was determined by the quality of its management, which is reflected in the extent to which it has met its own key performance targets and metrics, in judging whether its expenditure and revenue requirement submission is reasonable? Please discuss fully.

(d) Does the IESO consider safety of its employees important to their level of engagement? Please discuss.

(e) Does the IESO consider itself a stakeholder in its stakeholding process, or is it the sponsor of its submission, seeking the input of stakeholders?

(f) Should not the scorecard also apply to some outcomes which the IESO can substantially influence, though not completely control? Please discuss with reference to the proposed scorecard in this case.

(g) Please confirm that in evaluating the cost-effectiveness of the IESO's activities, the fact that the OEB does and should look to the success, or failure of the programs, the output of which the IESO substantially influences, as well as those it controls.

RESPONSE

a) i) Please see the IESO's evidence at Ex C-1-1 page 2 where the IESO stated that:

> The IESO is supportive of a scorecard to assist the Board in its decision making but it is not clear to the IESO which of the scorecard metrics the Board will find useful when evaluating the IESO's proposed expenditure and revenue requirement. If the Board does not find that one or more of the proposed metrics included in the IESO's scorecard are useful to it in this way, the IESO asks that it not be required to include those metrics in any scorecards filed with subsequent Revenue Requirement Submissions. For those measures the Board finds helpful with its decision making, the IESO will continue tracking the results as recommended on page 14 of the Report.

ii) Please refer to the response to part (a) i) above.

iii) Please refer to Exhibit C-1-1 under the section heading, Targets.

(b) The 2017 IESO Internal Scorecard is the 10 key performance metrics addressed in the 2017-2019 Business Plan at pages 19-24 of Exhibit A-2-2.

(c) i) Please refer to page 10 of Exhibit C-1-1, Attachment 1.

ii) Please refer to the response to Energy Probe Interrogatory 16 part (d) at Exhibit I, Tab 5.0, Schedule 5.16.

iii) Please refer to the response to part (c) ii) above.

(d) The IESO does consider the safety of its employees important. The IESO is committed to promoting and maintaining the health and safety of its employees in an injury-free and healthy workplace. The IESO requires that contractors and subcontractors maintain a standard of safety equivalent to that of the IESO when working at IESO premises.

(e) The IESO considered itself a stakeholder in the process as stated by Elenchus in the Report at page 16 of Exhibit C-1-1, Attachment 1:

> Elenchus facilitated two stakeholder sessions during which Elenchus shared its perspective on the development of appropriate IESO measures and listened to the feedback and comments of the stakeholders. **The IESO participated throughout the process as one of the stakeholders.** Elenchus also conducted one-on-one calls with each of the participating organizations and invited written comments. (emphasis added)

(f) Please refer to pages 2-3 of Exhibit C-1-1 regarding System View Metrics and section 1.3 starting on page 12 of Exhibit C-1-1, Attachment 1.

(g) Please refer to the response to OEB Staff Interrogatory 11 at Exhibit I, Tab 5.1, Schedule1.11.

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BOMA INTERROGATORY 21

Issue 5.1

INTERROGATORY

Ref: ***Elenchus, Appendix D, p4***

(a) Please provide pertinent details on both the settlement auditor who performs the audit, at what frequency. What is the substance of CSAE3416? Please provide copies of both the most recent auditor's reports, and the Terms of Reference for the reports.

(b) Please provide information on D80 review, and a copy of CICA8600, and the most recent Review Report, and its Terms of Reference.

RESPONSE

(a) The information requested is available in the report in Attachment 1.

(b) The IESO's Dispatch Scheduling and Optimization (DSO) tool is the software program that implements the dispatch algorithms, calculates market clearing prices and formulates dispatch instructions for generators and loads. The DSO tool finds an optimal outcome every five minutes by integrating market and reliability priorities. Accurately calculated prices and precise dispatch instructions ensure all Ontario electricity consumers are well served.

During the review period, there was nothing that came to the attention of the audit firm PricewaterhouseCoopers which would indicate that the dispatch algorithms were not operating in accordance with the relevant market rules.

The DSO review and Terms of Reference are included as Attachment 2 and 3, respectively.

Section 8600 of the Canadian Institute of Chartered Accountants (CICA) handbook Reviews of Compliance with Agreements and Regulations provides guidance in addition to that set out in Section 8100, General Review Standards, when a review engagement is undertaken to report on an enterprise's compliance with conditions established by provisions of an agreement or regulation. For further details, refer to section 8600 of the Canadian Institute of Chartered Accountants (CICA) handbook.

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Independent Electricity System Operator

Report on Controls Placed in Operation and Tests of Operating Effectiveness for the Settlement Processes and Systems

Canadian Standard for Assurance Engagements (CSAE 3416)

For the period January 1, 2017 to June 30, 2017

ieso
Independent Electricity System Operator

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Independent Service Auditors' Report

Building a better working world

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Independent Service Auditors' Report on a Description of a Service Organization's System and the Suitability of the Design and Operating Effectiveness of Controls

To the Management of the Independent Electricity System Operator

Scope
We have audited the Independent Electricity System Operator's (IESO) description of its' settlement operations system for processing user entities' transactions throughout the period of January 1, 2017 to June 30, 2017 (description) and the suitability of the design and operating effectiveness of controls to achieve the related control objectives stated in the description.

The IESO uses a subservice organization, Wall Street Systems, to support the operations and maintenance of the Wallstreet Treasura system. The description includes only the controls and related control objectives of the IESO and excludes the control objectives and related controls of the subservice organization. Our audit did not extend to controls of the subservice organization.

IESO's responsibilities
The IESO has provided the accompanying assertion titled, IESO's assertion regarding the settlement operations processes and systems (assertion) about the fairness of the presentation of the description and suitability of the design and operating effectiveness of the controls to achieve the related control objectives stated in the description. The IESO is responsible for preparing the description and for the assertion, including the completeness, accuracy, and method of presentation of the description and the assertion, providing the services covered by the description, specifying the control objectives and stating them in the description, identifying the risks that threaten the achievement of the control objectives, selecting the criteria, and designing, implementing, and documenting controls to achieve the related control objectives stated in the description.

Our independence and quality control
We have compiled with the relevant rules of professional conduct/code of ethics applicable to the practice of public accounting and related to the assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

The firm applies Canadian Standard on Quality Control 1, and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Building a better working world

Service auditor's responsibilities
Our responsibility is to express an opinion on the fairness of the presentation of the description and on the suitability of the design and operating effectiveness of the controls to achieve the related control objectives stated in the description, based on our audit. We conducted our audit in accordance with Canadian Standard on Assurance Engagements 3416, *Reporting on Controls at a Service Organization*, set out in the CPA Canada Handbook – Assurance. This standard requires that we plan and perform our audit to obtain reasonable assurance about whether, in all material respects, the description is fairly presented and the controls were suitably designed and operating effectively to achieve the related control objectives stated in the description, throughout the period of January 1, 2017 to June 30, 2017.

An audit of a description of a service organization's system and the suitability of the design and operating effectiveness of the service organization's controls to achieve the related control objectives stated in the description involves performing procedures to obtain evidence about the fairness of the presentation of the description and the suitability of the design and operating effectiveness of those controls to achieve the related control objectives stated in the description. Our procedures included assessing the risks that the description is not fairly presented and that the controls were not suitably designed or operating effectively to achieve the related control objectives stated in the description. Our procedures also included testing the operating effectiveness of those controls that we consider necessary to provide reasonable assurance that the related control objectives stated in the description were achieved. An audit engagement of this type also includes evaluating the overall presentation of the description and the suitability of the control objectives states therein, and the suitability of the criteria specified by the service organization and described in the assertion. We believe that the evidence we obtained is sufficient and appropriate to provide a reasonable basis for our opinion.

Inherent limitations
The description is prepared to meet the common needs of a broad range of user entities and their independent auditors and may not, therefore, include every aspect of the system that each individual user entity may consider important in its own particular environment. Because of their nature, controls at a service organization may not prevent, or detect and correct, all errors or omissions in processing or reporting transactions. Also, the projection to the future of any evaluation of the fairness of the presentation of the description, or conclusions about the suitability of the design or operating effectiveness of the controls to achieve the related control objectives is subject to the risk that controls at a service organization may become inadequate or fail.

Opinion
In our opinion, in all material respects, based on the criteria described in the IESO's assertion:

1. the description fairly presents the settlement operations system that was designed and implemented throughout the period of January 1, 2017 to June 30, 2017.

2. the controls related to the control objectives stated in the description were suitably designed to provide reasonable assurance that the control objectives would be achieved if the controls operated effectively throughout the period of January 1, 2017 to June 30, 2017 and if user entities applied the complementary user entity controls contemplated in the design of the IESO's controls and if subservice organizations applied the controls contemplated in the design of the IESO's controls throughout the period January 1, 2017 to June 30, 2017.

3. the controls tested, which, together with the complementary user entity controls and subservice organization's controls referred to in the scope paragraph of this report if operating effectively, were those necessary to provide reasonable assurance that the control objectives stated in the description were achieved, operated effectively throughout the period of January 1, 2017 to June 30, 2017.

Description of tests of controls
The specific controls tested and the nature, timing, and results of those tests are listed in the accompanying Description of Control Objectives, Controls, Tests and Results of Tests (Description of Tests and Results).

Restricted use
This report, including the description of tests of controls and results thereof in the Description of Tests and Results, is intended solely for the information and use of the IESO, user entities of the IESO's system during some or all of the period of January 1, 2017 to June 30, 2017, and the independent auditors of such user entities, who have a sufficient understanding to consider it, along with other information including information about controls implemented by user entities themselves, when assessing the risks of material misstatements of user entities' financial statements. This report is not intended to be and should not be used by anyone other than these specified parties.

Ernst + Young LLP

August 21, 2017
Toronto, Canada

IESO's assertion regarding the settlement operations processes and systems

Power to Ontario.
On Demand.

Independent Electricity System Operator
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Toronto, Ontario M5W 4E5
t 905 855 6100
www.ieso.ca

August 21, 2017

We have prepared the accompanying *Description of the IESO's settlement operations system* (Description) of the Independent Electricity System Operator (Service Organization) for users of the system during some or all of the period January 1, 2017 to June 30, 2017 (user entities), and their independent auditors who have a sufficient understanding to consider the Description, along with other information, including information about controls implemented by user entities themselves, when assessing the risks of material misstatements of user entities' financial statements. We confirm, to the best of our knowledge and belief, that:

a. the Description fairly presents the settlement operation processes and systems (System) made available to user entities during the period January 1, 2017 to June 30, 2017 for processing their transactions. The Service Organization uses Wall Street Systems to support operations and maintenance of the Wallstreet Treasura System. The Description includes only the controls and related control objectives of the Service Organization and excludes the control objectives, and related controls of Wall Street Systems. The criteria we used in making this assertion were that the Description:

(1) presents how the System made available to user entities was designed and implemented to process relevant transactions, including:

- the types of services provided, including, the classes of transactions processed;
- the procedures, within both automated and manual systems, by which those services are provided, including by which transactions are initiated, authorized, recorded, processed, corrected as necessary, and transferred to the reports presented to user entities;

- the related accounting records, supporting information, and specific accounts that are used to initiate, authorize, record, process and report transactions; this includes the correction of incorrect information and how information is transferred to the reports prepared for user entities;

- how the System captures and addresses significant events and conditions, other than transactions;

- the process used to prepare reports or other information provided to user entities;

- specified control objectives and controls designed to achieve those objectives;

- controls that, in designing the System, we contemplated would be implemented by user entities in order to achieve the specified control objectives (Complementary User Entity Controls); and

- other aspects of our control environment, risk assessment process, information and communication systems (including the related business processes), control activities, and monitoring controls that are relevant to the services provided, including processing and reporting transactions of user entities.

(2) does not omit or distort information relevant to the scope of the System, while acknowledging that the Description is prepared to meet the common needs of a broad range of user entities and their independent auditors, and may not, therefore, include every aspect of the System that each individual user entity and its independent auditor may consider important in the user entity's own particular environment.

b. the Description includes relevant details of changes to the System during the period from January 1, 2017 to June 30, 2017.

c. the controls related to the control objectives stated in the Description, which together with the complementary user entity controls and subservice organization's controls referred to above if suitably designed and operating effectively, were suitably designed and operated effectively throughout the period January 1, 2017 to June 30, 2017 to achieve those control objectives. The criteria we used in making this assertion were that:

(1) the risks that threaten the achievement of the control objectives stated in the Description have been identified by management;

(2) the controls identified in the Description would, if operating as described, provide reasonable assurance that those risks would not prevent the control objectives stated in the Description from being achieved; and

(3) the controls were consistently applied as designed, including whether manual controls were applied by individuals who have the appropriate competence and authority.

Management of the Independent Electricity System Operator

Description of the IESO's settlement operations system

1. Overview of the IESO

The Independent Electricity System Operator (IESO) was established and continues to operate under the *Electricity Act, 1998* (Ontario), as amended (the "Act"). The IESO is a non-profit corporate entity without share capital with responsibilities for directing the operation and maintaining the reliability of the IESO-controlled grid, operating the IESO-administered markets, planning for the province's short, medium and long-term energy needs and fostering the development of a conservation culture in the province. The IESO operates on a 24-hour, seven day a week basis from its system control centre managing the production and flow of electricity to local distribution utilities and major wholesale customers in Ontario, while adhering to all appropriate operating and reliability standards. The objects of the IESO under the Act and Regulations are to:

- Exercise the powers and perform the duties assigned to the IESO under the Act, the regulations, directions, the Market Rules and its license;
- Enter into agreements with transmitters giving the IESO authority to direct the operation of their transmission systems;
- Direct the operation and maintain the reliability of the IESO-controlled grid (ICG) to promote the purposes of the Act;
- Establish and enforce criteria and standards relating to the reliability of the integrated power system;
- Work with the responsible authorities outside Ontario to coordinate the IESO's activities with their activities;
- Operate the IESO-administered market to promote the purposes of the Act;
- Establish and enforce standards and criteria relating to the reliability of transmission systems;
- Engage in activities related to contracting for the procurement of electricity supply, electricity capacity and conservation resources;
- Engage in activities related to settlements, payments under a contract entered into under the authority of this Act and payments provided for under the Act of the *Ontario Energy Board Act, 1998*;
- Engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario;

- Forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the short term, medium term and long term;
- Conduct independent planning for electricity generation, demand management, conservation and transmission;
- Engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;
- Engage in activities in support of system-wide goals for the amount of electricity to be produced from different energy sources;
- Engage in activities that facilitate load management;
- Engage in activities that promote electricity conservation and the efficient use of electricity;
- Assist the Ontario Energy Board by facilitating stability in rates for certain types of consumers;
- Collect and make public information relating to the short term, medium term and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs; and
- Engage in such other objects as may be prescribed by the regulations.

2. Purpose of the Description of the IESO's settlement operations system

The Market Rules specify that the IESO shall direct a comprehensive external audit on the controls for its settlement processes and procedures every two years.

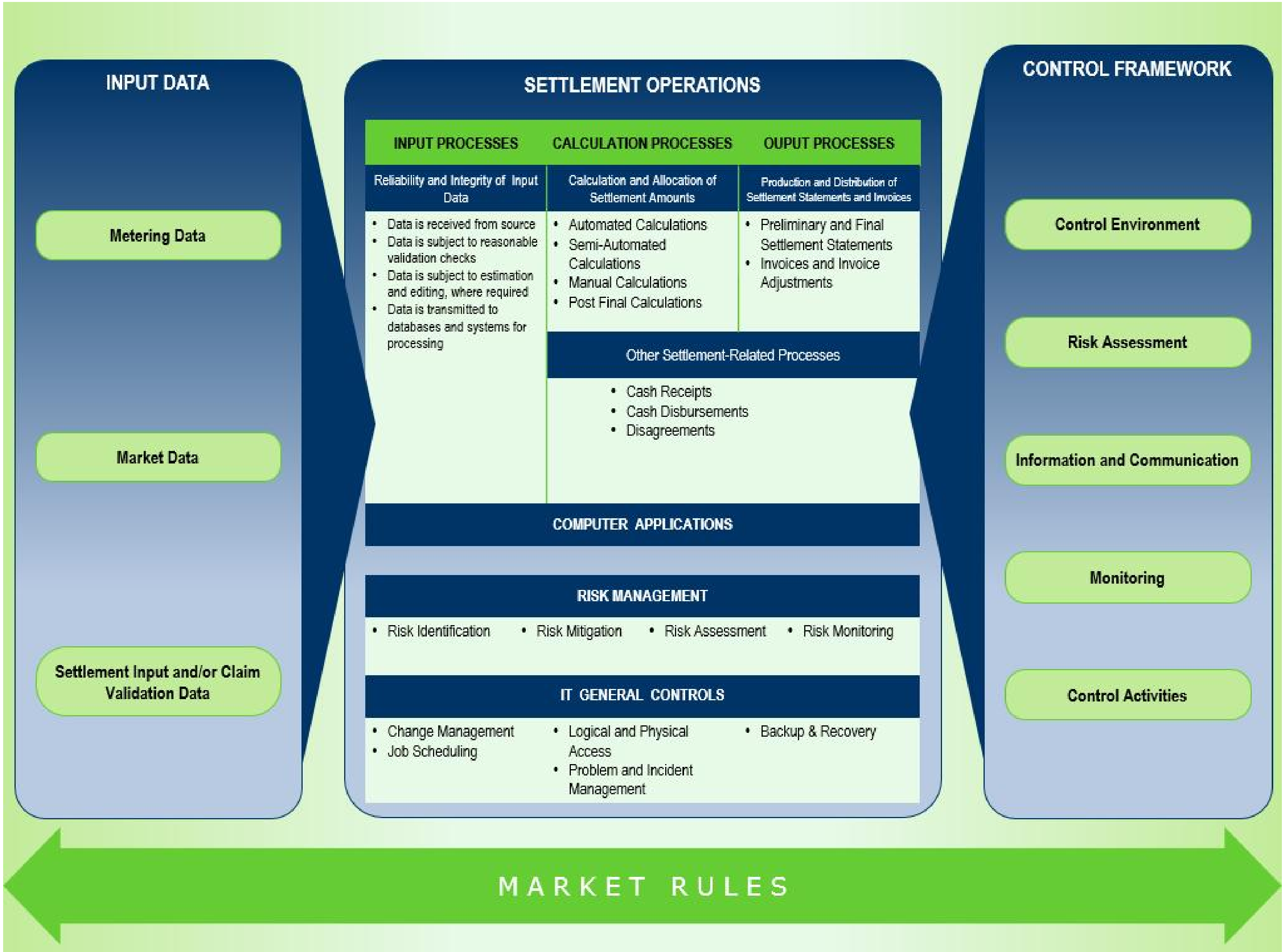
The IESO completes a CSAE 3416 Type 2 audit biennially to demonstrate to our stakeholders that management has designed and has effective controls in-place to manage the settlements process. Commencing in 2017, the IESO has also undertaken an American Institute of Certified Public Accountants (AICPA) SOC 2 Type 1 report to address security and confidentiality.

A visual description of the IESO's settlement processes and associated procedures and controls is contained in the section "Description of Control Objectives, Controls, Tests and Results of Tests" below. Programs outside of the market that the IESO settles on behalf of other organizations under service level agreements are excluded from the scope of this audit e.g. Northern Industrial Electricity Rebate Program on behalf of the Ontario Ministry of Natural Resources.

This description of the IESO's controls is intended to provide Market Participants and their auditors with an overview of the controls surrounding the IESO's Settlement Operations and the underlying information system environment that may be relevant to Market Participants' internal controls as they relate to an audit of financial statements.

3. Conceptual Overview

The diagram below provides a conceptual overview of the components of the IESO's Settlement Operations function. A more detailed description of each of these components is set out in the sub-sections that follow.


INPUT DATA
Metering Data
Market Data
Settlement Input and/or Claim Validation Data
SETTLEMENT OPERATIONS
INPUT PROCESSES
CALCULATION PROCESSES
OUPUT PROCESSES
Reliability and Integrity of Input Data
Calculation and Allocation of Settlement Amounts
Production and Distribution of Settlement Statements and Invoices
• Data is received from source
• Data is subject to reasonable validation checks
• Data is subject to estimation and editing, where required
• Data is transmitted to databases and systems for processing
• Automated Calculations
• Semi-Automated Calculations
• Manual Calculations
• Post Final Calculations
• Preliminary and Final Settlement Statements
• Invoices and Invoice Adjustments
Other Settlement-Related Processes
• Cash Receipts
• Cash Disbursements
• Disagreements
COMPUTER APPLICATIONS
RISK MANAGEMENT
• Risk Identification
• Risk Mitigation
• Risk Assessment
• Risk Monitoring
IT GENERAL CONTROLS
• Change Management
• Job Scheduling
• Logical and Physical Access
• Problem and Incident Management
• Backup & Recovery
CONTROL FRAMEWORK
Control Environment
Risk Assessment
Information and Communication
Monitoring
Control Activities
MARKET RULES

4. The IESO's Control Framework

This sub-section provides a more detailed description of the five components of the IESO's control framework.

4.1. Control Environment

The IESO's control environment reflects the mindset of its management and the overall attitude, awareness and actions of the IESO's Board of Directors, management and other stakeholders concerning the importance of internal control and the emphasis placed on control in the company's policies, procedures, methods and organizational structure. Relevant aspects of the control environment are summarized below.

4.1.1. Regulatory

The IESO has the authority under the Act to make rules governing the IESO-controlled grid and establishing and governing the markets related to electricity and ancillary services.

The IESO also operates under standards established by the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). NPCC is one of the Regional Entities that carries out NERC's mandate and establishes criteria and standards for ensuring reliable operation of the control areas under its jurisdiction. At the provincial level, the IESO usage fees and licence conditions are approved by the Ontario Energy Board and at the federal level the National Energy Board, grants export permits and approves international power lines.

In the United States, the IESO voluntarily participates from time to time in the American regulatory proceedings before the Federal Energy Regulatory Commission, United States Department of Energy and state regulatory commissions because of the relevance to Ontario of the development of reliability standards, market design and industry structure in the United States.

4.1.2. Board of Directors & Committees

The IESO is governed by a Board of Directors of up to 11 persons, 10 of whom are appointed by the Minister of Energy. The President and Chief Executive Officer (CEO) of the IESO is appointed by the Board of Directors and is also a Director. The Board of Director members cannot have a material relationship with any generator, distributor, transmitter, retailer or any other Market Participant thus assuring their independence. The IESO Board of Directors provides oversight to the executive leadership team in the management of the company's business and affairs. As part of its responsibilities, the Board approves the Market Rules, policies and guidelines that govern the IESO-administered markets and operation of the IESO-controlled grid.

Members of the Board of Directors are appointed for an initial two-year term and may be appointed for successive terms not exceeding two years. The Board of Directors carries out its responsibilities in part through Committees that oversee specific aspects of the IESO's business. These Committees are the Audit Committee and the Human Resources and Governance Committee.

In addition, two panels assist the Board in ensuring the proper functioning and governance of the IESO-administered markets and the IESO-controlled grid. These are the Technical Panel and the Dispute Resolution Panel. There is also a Stakeholder Advisory Committee that provides policy level advice. A short description of the Panels and Stakeholder Advisory Committee follows.

4.1.2.1. Technical Panel

The Technical Panel reviews and proposes amendments to the Market Rules on an ongoing basis and advises the Board of Directors on specific technical issues related to the operation of the IESO-administered markets and IESO-controlled grid as may be referred to it. The Technical Panel consists of 13 members, 11 of which are representatives of the electricity sector, and two are employees of the IESO. Additionally there is one liaison from the Ontario Energy Board.

4.1.2.2. Dispute Resolution Panel

The Dispute Resolution Panel mediates and arbitrates disputes:

- Under the Market Rules or certain agreements to which the IESO is a party;
- Between the IESO and Market Participants regarding the application and interpretation of the Market Rules;
- Relating to orders by the IESO denying authorization to a prospective Market Participant or denying registration to a prospective Metering Service Provider (MSP); and
- Between Market Participants which do not necessarily involve the IESO.

4.1.2.3. Stakeholder Advisory Committee

The Stakeholder Advisory Committee is a forum for its members to be informed of IESO activities and to provide timely policy level advice to the IESO Board and IESO management on material matters relating to the existing IESO-administered markets, the future evolution of the markets, the planning of the power system; the design delivery, and funding of the conservation programs, the procurement of generation resources and any other matters of concern to stakeholders. The Stakeholder Advisory Committee comprises 16 members reflective of stakeholder constituencies with a direct interest in IESO decisions.

4.1.3. Stakeholder Engagement

The IESO conducts broad-based consultations soliciting stakeholder advice on key operational and implementation-related issues. These consultations are done through various stakeholder forums and are driven by a Stakeholder Engagement Plan which is developed for each initiative or issue.

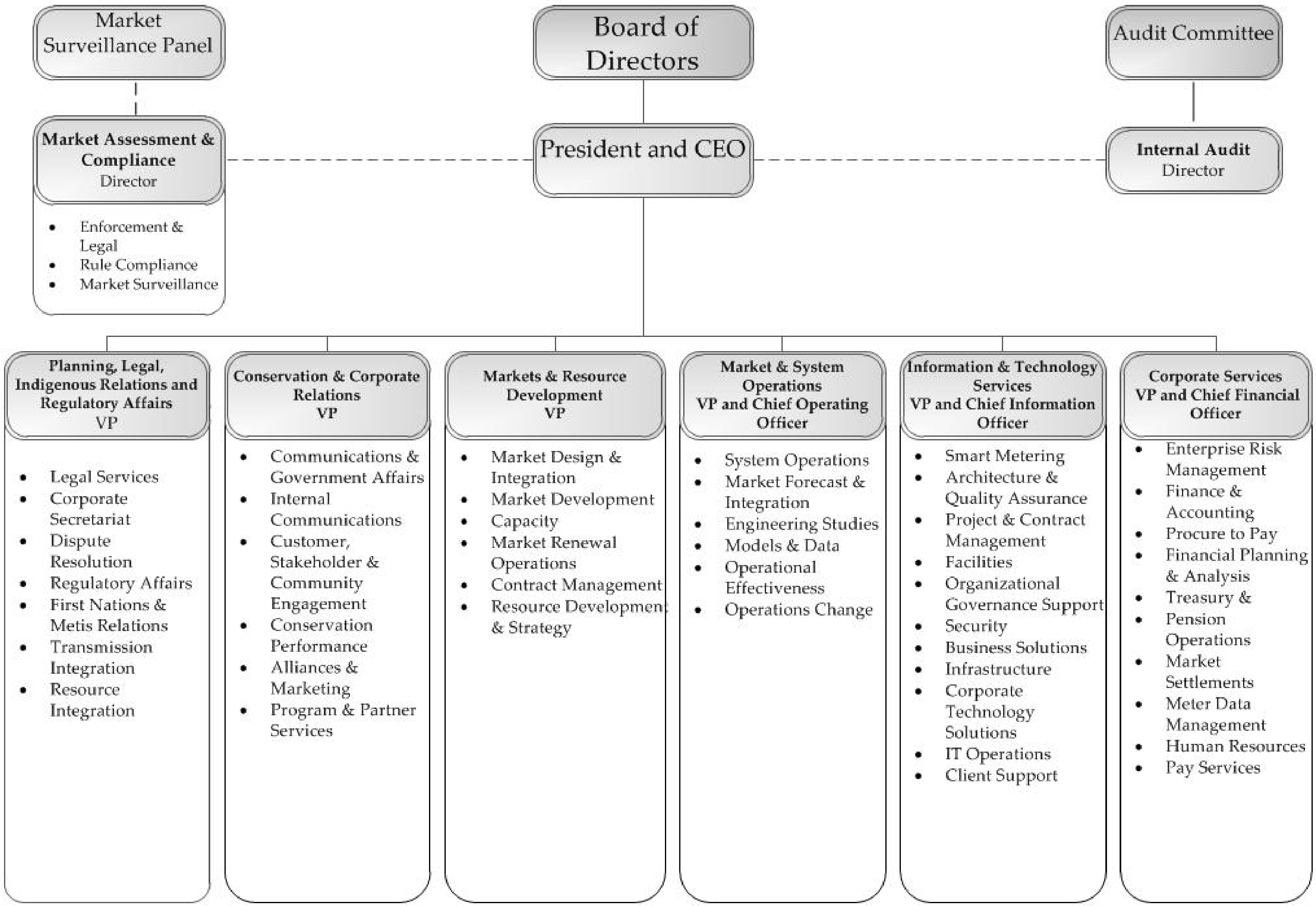
IESO maintains ongoing communication with external stakeholders to help ensure the IESO-administered markets and related processes are understood, and that adequate guidance is provided to participants on how to participate and use the related IT systems in these markets. Market Rules, IT system user manuals, and process and procedural documentation are all made available on the IESO website. The IESO website is also used to communicate any changes to Market Rules, related IT systems, and associated process and procedural documentation to external stakeholders through posted release notes.

4.1.4. IESO Organizational Structure

The Board of Directors appoints the President and CEO to oversee and direct the operations of the IESO. The President and CEO is supported by the Executive Team that leads various functional departments that manage and perform the day-to-day operations of the IESO.

The Executive Leadership Team, which includes the President and CEO, meets regularly to discuss all areas of IESO's business. This team is responsible for establishing corporate policies and procedures and for creating and maintaining a control conscious environment. An organization chart follows.

Independent Electricity System Operator



4.1.5. Management's Control Philosophy

The IESO Executive Leadership Team and the Board of Directors are committed to displaying and maintaining the highest level of integrity and ethical values, and providing a safe and ethical environment for staff, consistent with its corporate vision, mission and values. This ethical climate has a positive influence on individual behaviour and in turn serves to enhance the overall effectiveness of business process controls as well as to reduce the risk of fraud within the organization.

Ethical commitment is fostered through issuance of the IESO Code of Conduct and establishment of an "EthicsLine Program". The Code of Conduct sets out the standards of business conduct required by employees, officers and agents of the IESO. Adherence to the Code of Conduct is a condition of employment or of affiliation with the IESO. IESO employees are required to reaffirm acceptance of the Code of Conduct along with completing related training on an annual basis. Specifically, the Code of Conduct provides detailed guidance on compliance with laws and policies, protection of confidential information, safeguarding of assets and the handling of conflicts of interest. Contractors and third-parties are also required to sign a non-disclosure agreement as condition of employment by the IESO. The non-disclosure agreement clearly defines confidential information at the IESO and the proper handling of such information.

The IESO has established an EthicsLine Program that provides an alternative means for employees to anonymously communicate information concerning wrongdoing or improper or inappropriate behaviour, and to ensure that employees are treated fairly and are protected from reprisal from disclosure.

4.1.6. Management's Commitment to Competence

The IESO Executive Leadership Team is committed to recruiting, maintaining, developing and retaining a highly competent work force. To ensure that staff have appropriate skills for their jobs, the IESO has written job descriptions and sponsors both in-house and external training and continuing education to supplement on-the-job training. IESO management has also established procedures to guide staff in carrying out their responsibilities and has provided staff with the appropriate tools to perform their various functions. Immediate Supervisors/Managers provide annual performance assessment for employees. The IESO has formal hiring practices designed to ensure that new employees are qualified for their job responsibilities as documented in the written job descriptions. As part of the hiring practices, the IESO follows-up on references submitted by potential employees, requires that new employees sign a confidentiality agreement and performs security checks on all new hires.

4.2. Risk Assessment

4.2.1. Enterprise Risk Management

The IESO Executive Leadership Team (ELT) with the oversight of the Board of Directors has established and implemented a process to manage risks effectively and efficiently across the IESO. The IESO's Enterprise Risk Management (ERM) process supports corporate governance responsibilities in providing a structured approach to identifying, assessing, managing and monitoring potential events that may affect the achievement of its organizational objectives. The ERM program assists ELT and the Board of Directors in fostering an environment that is risk aware. IESO Executive Leadership Team uses defined risk assessment criteria to assess the risks to the organization in meeting its objectives and reports the resulting risk profile to the Board of Directors at least annually with quarterly updates on the management of key risks and actions taken to mitigate any unacceptable residual risks that have been identified.

Settlements staff complete a risk identification and assessment exercise on a quarterly basis to determine potential risk events that would hinder the achievement of the Settlement Process Business objectives. This process is based on ERM principles.

The IESO has the following control objective related to enterprise risk management:

- Controls provide reasonable assurance that settlement related enterprise process risks are identified, assessed, prioritized, mitigated and maintained in accordance with the IESO's Enterprise Risk Management policy.

4.2.2. Internal Audit

The operations of the IESO and supporting information systems are subject to review by the IESO Internal Audit department. Internal Audit has unrestricted access to the Audit Committee of the Board of Directors and reports administratively to the Chief Executive Officer and functionally to the Chair, Audit Committee. Internal Audit provides independent and objective assurance and consulting services on the design and effectiveness of the IESO's system of internal control, risk management and governance processes. The scope of Internal Audit work encompasses all aspects of the IESO business, responsibilities and obligations. Internal Audit provides high quality services by utilizing leading practices in its approach and methodology and in making value-added recommendations. Results of all audits are communicated in written reports that are presented to members of the Executive Leadership Team and the Audit Committee of the Board of Directors.

On an annual basis, Internal Audit develops a three-year Audit Plan that helps to ensure that Internal Audit is focusing on areas of most value to the organization. Development of the Audit Plan considers the ERM risk assessment results, the relative risk of areas or auditable units that could be reviewed by Internal Audit, and input from Management and the Board of Directors. The Audit Plan is approved by the Audit Committee of the Board of Directors.

4.3. Information and Communication

The IESO has also implemented various means of communicating significant events in a timely manner with employees and stakeholders. For employees these methods include electronic mail messages, orientation for new hires, and an intranet site. Managers/Supervisors also hold periodic staff meetings as appropriate and periodically the CEO holds "Town Hall" meetings with all staff. For Stakeholders, in addition to electronic methods, newsletters and working groups, the Conservation & Corporate Relations Group of the IESO has responsibility for providing ongoing two way communication with, and support to, Stakeholders.

In addition to the general communications from management above, user documentation, process and procedural documentation are made available to internal users via IESO's intranet to provide employees with specific guidance on performance of settlement operations and processes. This includes but would not be limited to, internal settlement guidelines that are published to provide specific requirements for business processes, as well as various IT policies and procedures such as those related to change and release management, user access governance, problem identification and escalation, and infrastructure hardening.

4.4. Monitoring

Under the ERM process described above, the IESO's Executive Leadership Team reviews key corporate risks on a quarterly basis and reports to the Board accordingly or more frequently should the risk profile change significantly. As well, Internal Audit plays an important role in monitoring risks and controls.

In addition, the Market Assessment and Compliance Division (MACD) monitors the Market Participants for compliance with the Market Rules. Through continuous monitoring of the market and Market Participant behaviour, MACD detects flaws in the market and anomalous conduct; and also ensure all parties' obligations are met. In addition, the IESO, through MACD, works with stakeholders to develop greater clarity and precision on compliance with Market Rules.

4.5. Control Activities

The IESO's Settlement control objectives and related controls are included in the following section of this report "Description of IESO Settlement Operations."

5. Description of IESO Settlement Operations

5.1. Governing and Operating Agreements

The Market Rules and the Ontario Energy Board licence provide the framework within which the IESO operates. The IESO also has operating agreements with external operating entities and external electricity systems interconnected with Ontario.

5.2. Input Data

Settlement processes for calculating and allocating settlement amounts rely on the following sources of data:

- Metering Data
- Market Data
- Settlement Input and/or Claim Validation Data

5.2.1. Metering Data (Control Objectives 1 and 2)

Revenue metering data is integral to the process of settling the IESO-administered markets. It is the primary basis for deriving all settlement charges and payments that will be made or received by Market Participants for their physical market transactions. All quantities of energy bought or sold by Market Participants must be measured and recorded by registered revenue metering installations. Therefore, the measurement of these quantities must be accurate.

Metering personnel review MSPs' metering installation registration submissions via Online IESO for compliance with the technical requirements set out in market manuals, standards and procedures. In addition, Metering personnel checks that the Site Specific Loss Adjustment (SSLA) and the Measurement Error Correction (MEC) registers have been signed by a Registered Professional Engineer and the Engineering Unit Report (EUR) and the

Site Registration Report (SRR) have been accepted by the MSP. Metering personnel accept the registration of the Metering Installation when all criteria have been met.

Each day the MV-90 system collects metering data from the revenue meters of Metered Market Participants. The MV-90 system and Settlement personnel then perform validation, estimation and editing procedures on the data before it is transferred to the MV-STAR system for further processing and ultimately to the Commercial Reconciliation System (CRS) for use in the settlement processes. Settlement personnel check the number of meters that transferred data to MV-STAR for reasonableness.

The MV-90 system automatically transmits failed validations to the Meter Trouble Reporting System which then issues a Meter Trouble Report (MTR) for each failure. MTRs are sent to Settlement personnel for review and analysis prior to being closed or sent to the MSP for resolution.

To demonstrate that newly registered metering installations have been commissioned in accordance with the Market Rules, MSP's are required to submit metering installation commissioning reports via Online IESO for review and acceptance. Periodically, Metering personnel perform audits of metering installations to assess that the metering installations are registered in accordance with the Market Rules. The IESO has the following control objectives related to metering data:

- Controls provide reasonable assurance that Market Participant contract relationship information and registered new or updated meters are recorded in the IESO's systems completely, accurately, and timely in accordance with the Market Rules.
- Controls provide reasonable assurance that metering data used in settlements calculations is received from registered meters and processed in the IESO's system completely, accurately, and timely in accordance with the Market Rules.

5.2.2. Market Data (Control Objectives 3, 4, and 5)

5.2.2.1. Physical Market Data

Physical market data is real-time energy and operating reserve market data submitted by Market Participants, including bids and offers for dispatchable resources and schedules or forecasts of energy production for non-dispatchable resources. This data is also used to generate additional settlement input information, such as market clearing prices and schedule quantities for dispatchable resources. This data is transmitted to the MIM system before it is transferred to the CRS for use in the settlement process.

Physical market data also includes Physical Bilateral Contract data.

Bids and Offers

The market clearing price for electricity in Ontario is determined based on physical market data – including offers to produce electricity and bids to consume electricity. Offers from suppliers (Ontario generators and importers) are used to create the supply curve, and bids from consumers (Ontario loads and exports) are used to create the demand curve for electricity.

Physical market data for the real time and the operating reserve markets include information provided by Market Participants into the real-time scheduling system such as:

- Bids for dispatchable loads and exports to consume energy
- Offers for dispatchable generators and imports to supply energy
- Offers for exports, imports, dispatchable loads and dispatchable generators to supply operating reserve
- Schedules or forecasts of energy production from non-dispatchable resources such as self-scheduling generators, intermittent generators and transitional scheduling generators.

Dispatch data is submitted through the web-based Energy Market Interface (EMI). The system time-stamps the bids/offers and runs a series of validity checks to confirm that the data conforms to the specified format. The system:

- Generates an acknowledgement to Market Participants
- Notifies Market Participants of rejections
- Updates the valid set of bids/offers; and
- Checks bids and offers for lead times.

The validated bids/offers are stored in the MIM system for further processing before being transferred to the CRS.

Energy Prices and Schedules, Operating Reserve Prices and Schedules

Energy and operating reserve market bids, offers, forecasts and schedules are used by IESO real-time scheduling systems to generate additional settlement input information in maintaining a balance of generation and load for each 5-minute interval on the IESO-controlled grid. This includes:

- Constrained and market scheduled quantities for imports and exports, generators and dispatchable loads for the supply and consumption of energy
- Constrained and market scheduled quantities for imports, exports, dispatchable generators and dispatchable loads for the supply of operating reserve
- Market clearing prices for energy and three classes of operating reserve in Ontario
- Market clearing prices for energy and two classes of operating reserve in each of 14 intertie zones.

The data is transmitted to the MIM system before it is transferred to CRS for use in the settlement process.

Physical Bilateral Contract Data

Buying and selling Market Participants have the option of submitting physical bilateral contract data to the IESO. This data allows the IESO to:

- Credit the buying Market Participant with the applicable market price for energy for the total physical bilateral contract quantities sold to them
- Debit the selling Market Participant with the applicable market price for energy for the total physical bilateral contract quantities sold by them
- Allocate some or all of the various components of hourly uplift assessed on the physical bilateral contract quantities between the buying Market Participant and the selling Market Participant as specified in the physical bilateral contract quantities.

The IESO verifies that the required data fields are complete and submitted within the valid timeframe. This data is stored in the MIM system before it is transferred to the CRS for use in the settlement process.

The IESO has the following control objective related to physical market data:

- Controls provide reasonable assurance that bids and offers are received and processed completely, accurately and timely in accordance with the Market Rules.

5.2.2.2. Financial Market Data – Transmission Rights Market

Transmission Rights are financial instruments that entitle the holder to a settlement amount based on locational differences in the settlement prices between the IESO control area and an intertie zone. A Transmission Rights Market Participant must be an authorized Market Participant in the IESO administered markets and have signed a Participation Agreement with the IESO prior to the date of the round of the Transmission Rights Auction (TRA).

Transmission Rights Market bids are submitted by Market Participants via the TRA system and the data generated is then transmitted directly to the CRS for subsequent use in the settlement process. Settlement personnel reviews auction results with data in CRS.

The IESO has the following control objective related to financial market data:

- Controls provide reasonable assurance that Transmission Rights Auction data in the Commercial Reconciliation System is received from the TRA system and is processed completely, accurately and timely in accordance with the Market Rules.

5.2.2.3. Reactive Support and Voltage Control (RSVC) Service Data

The IESO requests contracted generators to operate in condense or speed no load mode when additional reactive support is required on the IESO controlled grid. These requests are recorded by Control Room Operators in real-time in the Contract Manager tool including start time, end time and if a start-up is required.

The settlement of RSVC Service payments for generation in the Northeast of the province is not based on specific identification and selection of generators requested to operate in condense mode. Rather, the settlement is based on the operating conditions in the area that determine the number of units required without specifying the particular units. The data required for this assessment is tele-metered operational data including specific breaker conditions and energy flows.

The settlement of generators requested to operate in speed no load mode requires offer rates in effect at the time of the event and other rates stipulated in the underlying agreement. These offer rates are submitted by the Market Participant, validated by the IESO and loaded into the CRS to support the automated settlement calculation in addition to the stipulated contractual rates.

5.2.3. Settlement Input Data and/or Claim Validation Data (Control Objective 5)

The IESO processes and validates inputs for certain settlement amounts through the use of EUC tools. Settlement quantities are extracted directly from inputs received or calculated using EUC tools, and then these settlement amounts are entered into the CRS for application to settlement statements.

In general, the IESO receives inputs for EUC calculations from Market Participants as well as from internal IESO sources. Data is received from Market Participants through the following methods:

- Data submitted via online forms are accessed as read-only sources
- Data provided by e-mail is submitted to a common e-mail box that is automatically distributed to Settlement staff members

Data received from IESO internal sources is accessed in a read-only format, and the IESO applies certain controls to inputs and information.

The IESO has the following control objective related to data for EUC tool ("semi-automated") calculations and other settlement activities:

- Controls provide reasonable assurance that data used in semi-automated and manual calculations are received from Market Participants and processed completely, accurately and timely in accordance with the Market Rules.
- Controls provide reasonable assurance that input data and claim information used in calculating settlement amounts are complete and accurate, in accordance with the Market Rules.

5.2.3.1. General Controls Applied to Inputs for EUC Calculations

The IESO receives data for EUC calculations and other settlement activities directly from Market Participants and from internal IESO sources.

Certain data for EUC calculations and other settlement activities is received directly from Market Participants via the following types of online forms:

- OPG Rebate Returned to the IESO
- Submission of Transmission Service Charges for Embedded Generation
- NUG Adjustment Amount Information
- Global Adjustment Amount Information
- Regulated Price Plan vs. Market Price - Variance for Conventional Meters
- Retailer Payments for Contract Price vs. HOEP for Regulated Consumers with a Retail Contract
- Regulated Price Plan vs. Market Price - Variance for Smart Meters
- Embedded Generation Information and Class A Load
- Regulated Price Plan - Final Variance Settlement Amount
- Licensed Distributor Claims for the Renewable Energy Standard Offer Program
- Embedded Distributor Claims for the Renewable Energy Standard Offer Program
- Hydroelectric Contract Initiative Program
- Feed-in Tariff Program– LDC
- Feed-in Tariff Program – Embedded LDC
- Generation Cost Guarantee Information
- Ontario Clean Energy Benefit (-10%) Program - LDC
- Ontario Clean Energy Benefit (-10%) Program – Unit Sub-Meter Provider
- Coincident Peak
- Procurement Contracts
- Ontario Electricity Support Program (OESP) – LDC & USMP
- Ontario Electricity Support Program (OESP) – Prior Month Adjustments
- Ontario Electricity Support Program (OESP) – Service Providers
- Ontario Rebate for Electricity Consumers (OREC) – LDC
- Ontario Rebate for Electricity Consumers (OREC) – Sub-Meter Provider

Other data for EUC calculations and other settlement activities is received from Market Participants through other methods of transmission:

- Market Participants provide certain settlement data directly to the IESO by e-mail to a common IESO e-mail box that is automatically distributed to Settlement staff members. For example, hourly energy losses, calculated as per terms of the AGC Agreements are submitted directly to the IESO by Market Participants.
- Market Participants provide certain settlement data through IESO Collaboration portal communities. For example, hourly measurement data is submitted by for hydroelectric prescribed assets that are not directly connected to IESO Controlled Grid. Settlement staff members have read-only access to these portal communities to retrieve data provided.

Certain data for EUC calculations and other settlement activities is received from IESO internal sources:

- Certain settlement input data is prepared by one IESO department and used in manual calculations and activities executed by another IESO department. For example, the generation resources that provide regulation service, the quantity provided and the relevant hour are gathered by Ex-Post personnel. This data is provided to Settlement staff for calculation of the AGC settlement quantities, in accordance with the ancillary services contract. Data supplied by one IESO department for use in end-user computing tools (other than low risk tools) by another IESO department are provided via a read-only interface.
- Certain settlement input data used in manual calculations and activities is extracted from databases that are supported by IESO's IT-department, such as the CRS database or the System Data Repository (SDR) database. Data is extracted from these read-only sources using queries.
- Certain settlement input data used in manual calculations and activities is prepared by IT-executed queries which deliver data in read-only format.

5.2.3.2. Controls Applied to Specific EUC Calculations and Activity Inputs

In addition to the control procedures described above, the IESO applies specific controls to inputs and information for the following settlements:

- Ancillary Service contracts (with the exception of Reactive Support, which is semi-automated)
- Real time generation cost guarantee and day-ahead production cost guarantee
- Export transmission tariff for segregated mode of operation
- Outage cancellation charge
- Intertie Offer Guarantee Offset
- Local Market Power/congestion management settlement
- Additional compensation relating to administrative pricing

5.2.3.3. Ancillary Services

Under the authority of the IESO market rules, Operational Effectiveness personnel negotiate contracts with generators and loads as appropriate to provide the following ancillary services:

- Regulation service
- Black start capability service
- Reactive Support and Voltage Control service (RSVC)
- Reliability Must-Run Contracts

These reliability services are used to support power system reliability in addition to other market mechanisms. The IESO executes these contracts in accordance with the IESO's Organizational Authority Register.

These programs are settled as described below.

Frequency Regulation Service

For regulation service, Ex-Post personnel review the Control Room log daily. Ex-Post personnel take the hourly data on quantities provided and facilities providing regulation service, enter this data on spreadsheets and confirm the data with the ancillary service providers. At the end of each month, Ex-Post personnel send the completed spreadsheets to Settlement personnel for calculation of the settlement amounts.

Black Start Capability Service

For black start capability service, Settlement personnel enter contracted monthly payment amounts into CRS.

Reactive Support and Voltage Control (RSVC) Service

RSVC is described above in section 5.2.2.3.

5.2.3.4. Generator Station Service Rebate

Generators that have separately metered station service may incur uplifts or non-hourly settlement amounts. In these cases, the generator is entitled to be reimbursed for these amounts. Generators wishing to participate in this program submit a request identifying the locations that qualify.

5.2.3.5. Real Time Generation Cost Guarantee and Day-Ahead Production Cost Guarantee

Two guarantees have been established to encourage generators to come to market by responding to market signals and synchronizing their units. These guarantees – real-time cost guarantee (RT-GCG) and day-ahead production cost guarantee (DA-PCG) – reduce the risk for the generator of coming to market by providing a guarantee payment if specific unit start-up costs are not covered by market revenues. After a trade day, eligible Market Participants submit combined guaranteed costs for each eligible synchronizing event. On a daily basis, the RT-GCG/DA-PCG tool executes a filter to identify Market Participant facilities that meet the conditions for a valid RT-GCG or DA-PCG start. Facilities rejected by the automated process are flagged and Settlement personnel manually review these events. If the manual review identifies that a start was inappropriately rejected by the automated process, Settlement staff alter the valid/rejected flags and sign-off on the change. At month-end, Settlement staff prepare manual charges to distribute the costs paid for eligible RT-GCG and DA-PCG starts and enter them into CRS.

5.2.3.6. Export Transmission Tariff for Segregated Mode of Operation

At times, Ontario generators may operate in a manner in which they are physically disconnected from the Ontario grid. Instead, they generate and deliver energy directly to an adjacent Control Area. In such instances, the IESO records all occurrences of Market Participants operating their facilities in a Segregated Mode of Operation (SMO) and ensure that appropriate settlement of transmission tariffs and other applicable charges to the registered transmitter occur. On a monthly basis, Ex-Post personnel prepare the data specifying SMO events, and send it to Settlements.

5.2.3.7. Outage Cancellation Charge

Due to reliability concerns, IESO Market & System Operations (M&SO) may cancel an approved outage. When this occurs, Market Participants that are affected are compensated for incremental costs incurred as a result of the outage cancellation. Upon submission of the request for compensation, M&SO personnel evaluate the request for eligibility and confirm the amount requested. The Director, Market Operations or the Chief Operating Officer (COO) approves the request, and then sends the approved amount electronically to Settlements for entry into CRS.

5.2.3.8. Intertie Offer Guarantee Offset

Intertie Offer Guarantee (IOG) payments were introduced to reduce price risk for imports and therefore to encourage imports and help to ensure adequate supply of energy in Ontario. An importer is “locked-in” based on hour-ahead dispatch prices but settles on real-time energy price for the intertie zone, which may be different. The IOG ensures that, over the course of the hour, an importer will receive at least the average price of its offer. The IOG payment is calculated automatically by CRS.

The IOG is a reliability payment for imports. For hours in which the Market Participant is also exporting power out of Ontario (an ‘implied wheeling’), there is little reliability benefit. The IOG offset is a manual settlement calculation that claws back IOG payments for the import leg of implied wheels.

The Day Ahead Commitment Process allows importers to have their imports committed day-ahead, and to receive the greater of the day-ahead IOG and the real-time IOG if the import flows in real-time. These imports are also subject to the IOG offset process.

5.2.3.9. Local Market Power

Congestion Management Settlement Credit (CMSC) payments are made to eligible Market Participants when the unconstrained market schedule and the constrained dispatch schedule differ. This difference often occurs due to congestion when the physical capability of the transmission system cannot meet market requirements. Market Participants receive payments for their registered facilities based on the difference between the energy market price and the bid or offer prices for the registered facilities.

If a registered facility has Local Market Power (LMP) because of the local nature of the energy or related product, its offer/bid prices may lead to unreasonable levels of congestion management credits. Alternately, if a registered facility in a Constrained Off Watch Zone (COWZ) receives persistent and significant constrained off CMSC payments, some portion of these payments may be recoverable. The data from settlement for CMSC is electronically transmitted to a tool in the Market Assessment and Compliance Division (MACD) where it is screened against pre-defined criteria to identify recoverable payments. MACD personnel review the payments against additional criteria to determine ineligibility for CMSC. Upon completion of the investigation, MACD personnel submit lists of ineligible CMSC payments and send them electronically to Settlements for entry into CRS. The Supervisor, Market Assessment approves prior to sending to Settlements.

5.2.3.10. Congestion Management Settlement Credit Clawback

Settlements has an end use computing tool that applies defined and documented business rules to determine if CMSC was inappropriately paid to an import in a COWZ and calculates the adjustment amount. As part of the Settlements month end process, manual line items (MLI) are created and imported into CRS. Prior to importing into CRS, the MLI is reviewed and approved by the Supervisor, Customer Billing.

5.2.3.11. Additional Compensation for Administrative Pricing

The dispatch algorithm calculates energy and operating reserve market prices, which are normally published within five minutes of each 5-minute interval. When market pricing mechanisms are not functioning normally, the IESO administers prices for the affected intervals.

Within two business days of the occurrence, Ex-Post personnel "copy forward" from the "last good" interval up to 24 intervals and/or "copy back" from the "first good" interval up to 24 intervals. A maximum of 48 intervals can be administered using this methodology.

A Market Participant may submit a request for a settlement adjustment by submitting a Notice of Disagreement where the administrative prices are not adequate to cover the costs incurred. Eligibility for compensation is verified by MACD and Ex-Post staff.

5.3. Calculation and Allocation of Settlement Amounts (Control Objectives 6 and 7)

Settlement amounts are calculated and allocated:

- Automatically by IT-supported settlement systems including Meter Data Management System, the Transmission Tariff Distribution Calculator (TTDC) and the Commercial Reconciliation System (CRS)
- Semi-automatically by IESO staff, often using EUC tools
- Manually

The IESO has the following control objectives related to calculation and allocation of settlement amounts:

- Controls provide reasonable assurance that settlement payments and charges are calculated and allocated completely, accurately and timely in accordance with the Market Rules.
- Controls provide reasonable assurance that post-final calculations are calculated and allocated completely, accurately and timely in accordance with the Market Rules.

5.3.1. Automated calculations

In the majority of cases, settlement amounts and financial allocations are calculated automatically by IT-supported settlement systems with little manual intervention. The applications used to perform these calculations are identified below in Section 5.6 Computer Applications.

The bulk of the charges and credits are calculated automatically by the IESO's key computer applications that are maintained by the Information &Technology (I&TS) Services business unit. Refer to the section "Other Information Provided by the IESO" for a listing of all charge codes used during the audit period. While all charge codes can be calculated manually, the list of charge codes in the section "Other Information Provided by the IESO" specifically lists those that are calculated automatically by IT-supported settlement systems.

5.3.2. Semi-automated calculations

In some cases, settlement amounts are calculated and/or allocated in a semi-automated manner. That is, these quantities are determined on sub-systems outside the CRS, often using EUC tools. These processes sometimes include manual steps. The results of the semi-automated calculations are then entered into CRS. A description of these processes follows.

Semi-automated settlement amounts may be prepared using EUC tools (i.e. spreadsheets and databases). To help ensure the completeness, accuracy and validity of inputs to, as well as processing and outputs from these tools, the IESO has adopted controls for the development and maintenance of tools as follows:

- Standard – Acquisition and Maintenance of End User Computing Tools
- Procedure – Assess Risks of End User Computing Tools

The IESO periodically assesses the settlement calculations and associated EUC tools based upon risk considering the inherent likelihood and impact of error, consistent with this standard and procedure. The IESO also uses this standard and procedure to guide the implementation and execution of access control, backup, archiving, version control, security control, change control, testing, documentation, input control and development control.

IESO Policies, Standards and Procedures govern control of inputs, control of EUC execution and treatment of outputs. For medium and high-risk EUC tools, the IESO uses input data typically from read-only sources (see section 5.2.3.1 'General Controls Applied to Inputs for EUC Calculations'), and IESO staff execute a check tool version of the tool to increase assurance that unauthorized changes have not been made to a tool. The output of these tools is formatted as Manual Line Items (MLIs) for entry into CRS.

5.3.3. Manual Calculations

In cases where settlement amounts are calculated and/or allocated in a semi-automated manner, these amounts are manually entered into CRS by Settlement staff so that they can be applied to settlement statements.

Upon receipt of MLIs, Settlement personnel enter the data into CRS, then check and sign off that the data was entered correctly.

5.3.4. Post-Final Calculations

Post-final calculations occur after the final settlement statements have been issued for a trade day. They are triggered when settlement errors are discovered either by IESO personnel or by Market Participants and are not addressed by Notice of Disagreements (NoDs) including any payment that has been authorized by the appropriate body (e.g. IESO Board of Directors, Ontario Energy Board, legislation, regulation, Market Rule). Settlement errors may be the result of inaccurate meter data identified through meter data reconciliation activities or through meter audits. Errors related to other charges such as generation cost guarantees, intertie offer guarantees or global adjustment submission can also result in a need for post-final calculations.

Settlement personnel review the error against established criteria (e.g., Market Rule obligation, legislation, procedures, materiality) to determine whether a post-final calculation should be made or confirm that any other payments have been authorized by the appropriate body (e.g. IESO Board of Directors, Ontario Energy Board, legislation, regulation, Market Rule). The decision to proceed with a post-final calculation is documented and signed by the Senior Manager, Market Settlements.

When executing a post-final calculation for an energy adjustment due to inaccurate measurement data, Settlement personnel will:

- Assess corrected meter data submitted by the Metered Market Participant or the MSP for reasonability, where appropriate
- Estimate and approve a meter data correction, where required
- Assess revised delivery point data produced by an offline version of the MV-STAR system for reasonability
- Verify the results of an offline version of the Transmission Tariff Demand Calculator tool
- Verify that the energy adjustment calculated by an offline version of the CRS system is reasonable and reconciles within pre-defined tolerance
- Assess that the results of EUC tools to calculate and adjust Global Adjustment amounts for post-final calculations are reasonable
- Assess that manual line items prepared by a EUC tool that extracts adjustment amounts created by the offline version of the CRS system are reasonable

When executing a post-final calculation for a day-ahead production cost guarantee or real-time generation cost guarantee adjustment, Settlement personnel will:

- Confirm that a DA-PCG or RT-GCG data for each guarantee claim to be calculated by the GCG offline tool has been correctly loaded into the tool
- Manually investigate all claims that were rejected and validate 10% of claims that were determined to be valid based on eligibility rules
- Execute a check tool for a sample of 10% of real-time GCG offline events, to ensure that the offline tool is calculating claim amounts correctly. Differences greater than $100 are investigated and resolved.

5.4. Output Processes

Annually, the IESO publishes an "IESO Settlement Schedule and Payments Calendar" (SSPC) that specifies the dates when the IESO issues preliminary settlement statements, final settlement statements, and invoices. On the date specified in the SSPC, a settlement statement and/or an invoice is issued to each Market Participant as appropriate.

5.4.1. Production and Distribution of Preliminary and Final Settlement Statements (Control Objective 8)

Through the CRS, Settlement personnel publish a preliminary settlement statement for each Market Participant ten business days after each trade day. Preliminary settlement statements contain the market activity and charge types for the trade day as well as other charges not necessarily related to the trade day that was assessed. All charges must appear on a preliminary settlement statement before they can appear on a final settlement statement. Market Participants are expected to retrieve their preliminary settlement statement and confirm its accuracy[1]. Ten business days after publication of the preliminary settlement statement, the IESO prepares and publishes a final settlement statement for each Market Participant. Final settlement statements reflect any adjustments that may have been made to the preliminary settlement statements.

Settlements personnel review run time error logs daily, and as applicable errors are investigated and resolved. Settlement personnel review the Neutrality Report to confirm that the amounts owed to the market net out to the amount owed from the market.

The IESO has the following control objective related to the publication of preliminary and final settlement statements:

- Controls provide reasonable assurance that preliminary and final settlement statements provided to Market Participants are complete, accurate and timely in accordance with the Market Rules.

[1] Market Participants can submit Notices of Disagreement within four business days after publication of the preliminary settlement statement. See the section titled 'Notice of Disagreements' below

5.4.2. Production and Distribution of Invoices and Invoice Adjustments (Control Objective 9)

The IESO issues invoices monthly to each Market Participant who has undertaken a transaction in the physical market or weekly for financial market transactions. Each invoice issued to a Market Participant is based on all final settlement statements that are available for that billing period and preliminary settlement statements where a final settlement statement is not yet available. Any net difference between these preliminary statements and the subsequent final settlement statements is reflected in the invoice for the next billing period.

Finance personnel perform a number of reconciliations to ensure that invoice and invoice adjustments provided to Market Participants are accurate, complete and timely. Specifically, Finance personnel reconcile various system reports to ensure settlement data in CRS is transferred properly over to the Lawson for invoicing. Transactions between Lawson's Accounts Receivable modules, Payables modules and General Ledger modules are also reviewed and reconciled at each stage to ensure accurate transfer of data. The Manager, Finance and Accounting reviews and approves supporting documentation and direction provided from Settlement for invoice adjustments. Finally, processes are in place to ensure system generated invoices are issued properly and timely to Market Participants through the Managed File Transfer (MFT).

Manual invoices are produced for various costs that are not addressed by the settlement charge types that comprise the physical market settlement statements. Examples of such costs include interest charged on late payments, and compliance penalties. Manual invoices are issued upon receipt of approved supporting documents.

Each month, Finance personnel run a query for incomplete invoices to ensure all invoices are complete and ready for issuance.

The IESO has the following control objective related to the publication of invoices:

- Controls provide reasonable assurance that invoices and invoice adjustments that are provided to Market Participants are complete, accurate and timely in accordance with the Market Rules.

5.5. Other Settlement Related Processes

5.5.1. Cash Receipts and Cash Disbursements (Control Objectives 11 and 12)

The IESO-administered markets are designed to clear market transactions to a net zero balance. All payments received from Market Participants are paid to the IESO bank via electronic funds transfer or wire transfer on the date specified in the SSPC which is two business days following the date on which invoices are issued. Payments from the IESO to Market Participants are made within two business days following the Market Participant payment date. The Treasury system automatically downloads bank balances and transactions detail daily. Finance personnel reconcile the bank balances and transactions on a monthly basis, and investigate any unclear or unreconciled items. The Treasury Analyst then submits the IESO's market Accounts Receivable file to Lawson in a pending state. Finance personnel subsequently post the associated journal entries in Lawson to clear the Cash Clearing account. On a monthly basis, Finance personnel reconcile the Electronic Funds Transfer (EFT) outbound payment file with the payment invoices on Accounts Receivable and Accounts Payable reports.

The IESO has the following control objective related to the processing of cash receipts and cash disbursements:

- Controls provide reasonable assurance that cash receipts for settlement charges due to the IESO are processed completely, accurately and on a timely basis in accordance with the Market Rules.
- Controls provide reasonable assurance that cash disbursements due to Market Participants are processed completely, accurately and timely in accordance with the Market Rules.

5.5.2. Notice of Disagreement (Control Objective 13)

Market Participants that disagree with any of the amounts that appear on their preliminary settlement statements submit a Notice of Disagreement (NoD) within four business days after the preliminary settlement statement is issued. Submitted NoDs are automatically time and date stamped by the NoD tool. Settlement personnel review all properly submitted NoDs against the Market Rules and other established criteria to determine if an adjustment to the preliminary settlement amount should be made. Settlement personnel implement approved disagreements and verify adjustments prior to issuing the appropriate settlement statement. Any adjustment resulting from a NoD will appear as a revised amount on the final settlement statement or a new amount on a subsequent preliminary statement.

The IESO has the following control objective related to the processing of NoDs:

- Controls provide reasonable assurance that disagreements are processed completely, accurately and timely in accordance with the Market Rules.

5.6. Computer Applications

This sub-section describes the key computer applications used by the IESO in the settlements process and that are maintained by the Information & Technology (I&TS) Services department. The applications listed below include those that provide data inputs, perform processing and calculate charges, produce settlement statements and invoices and manage the collection and disbursement of cash, facilitate internal and external communication, and store records.

5.6.1. Online IESO

Online IESO is the system where Market Participants can post information to the IESO in a safe, secure and efficient manner, replacing the need for email exchange in many instances. Online IESO offers a modern and consistent means for Market Participants to post messages, questions and comments in a collaborative manner while completing a variety of interactive business tasks. Specifically, it provides Market Participants with access to the following modules: Registration Online, Meter Installation Registration Online, Notice of Disagreement Online and Meter Trouble Reports Online. Access to Online IESO is given to authorized representatives from registered organizations through our registration online process.

5.6.2. Customer Data Management System (CDMS)

The Customer Data Management System is used to manage data regarding Market Participants and facilities. This web-based tool is the repository for registration information submitted during market participation authorization and facility registration. The system maintains lists and profiles of Market Participants, Metered Market Participants, Metered Service Providers, transmitters and distributors. The system is also the master registry for delivery point information; once created in this system, delivery point data is replicated to IESO market systems. The CDMS allows users to review their information and keep track of the status of their applications.

5.6.3. MV-90

The MV-90 system, also known as Meter Data Acquisition System (MDAS), allows the IESO to automatically manage the collection, validation, editing and storage of data from metering installations. Metering data is downloaded from MDAS to MDMS when it is first collected and then each time it is changed.

5.6.4. MV-STAR

The MV-STAR system, also known as Meter Data Management System (MDMS), is a data warehouse that receives, adjusts, totalizes and stores metering data. The system stores market relationship, delivery point, meter and meter reading data. It supports data versioning so that the state of customer data and system configuration parameters can be recovered at any point in time.

5.6.5. MV-Web

MV-Web allows Market Participants to view and retrieve meter data stored within the MV-STAR system. It also allows users to define associations to allow third party access to metering data. Users can receive the recorded and calculated quantities of interval load data.

5.6.6. Meter Trouble Reporting (MTR)

The Meter Trouble Reporting system (MTR) generates reports for problems that have occurred with the collection and/or validation of metering data from a Metered Market Participant's revenue meter. These reports are sent to the MSP and Metered Market Participant for the resolution of metering problems.

5.6.7. Transmission Tariff Demand Calculator (TTDC)

The Transmission Tariff Demand Calculator system is used to determine the transmission delivery point demand charge determinants monthly. These determinants are then passed to the Commercial Reconciliation Systems for processing.

5.6.8. Transmission Rights Auction (TRA)

The TRA system is used to facilitate the transmission rights market and is the system of record for the owner of transmission rights. The ownership information is updated based on the winners of the transmission rights auction and the release of transmission rights by the IESO.

5.6.9. Market Information Management (MIM)

The Market Information Management system (MIM) is the central database for the market data systems. The system consists of a series of databases, which store registration, market and systems operation data. The system receives and validates bid, offer and physical bilateral schedule data, for example, and then passes relevant data to CRS.

5.6.10. Managed File Transfers (MFT)

As part of the IESO's Information Publishing Systems, Managed File Transfer (MFT) is responsible for publishing both Market Participant confidential and public documents to the IESO web site. Access to Market Participant confidential information is available through the Report Repository Interface using a user ID and password. Market Participants retrieve their invoices, settlement statements and Statement of Activities and set up data files from this system.

5.6.11. Commercial Reconciliation System (CRS)

CRS collects data from other IESO systems, calculates the settlement amounts for the IESO-defined charge types, processes user-entered settlement adjustments (i.e. manual line items), generates financial exposure information for Market Participants, and generates preliminary and final settlement statements for IESO-administered markets.

5.6.12. Lawson

The IESO uses the Lawson General Ledger, Accounts Payable and Accounts Receivable applications as part of the settlement process. These applications handle the generation of invoices, as well as the maintenance of market accounts, and maintenance of Market Participant historical payment information. Lawson also creates electronic transfer files for payments.

5.6.13. Notice of Disagreement (NOD)

The Notice of Disagreement system is a tool that allows Market Participants to submit a Notice of Disagreement to the IESO and allows tracking of the submission through to completion. The workflow application allows tracking of actions taken on identified incidents to ensure the disagreement is processed in accordance with the timelines required by the Market Rules.

5.6.14. Treasura

The Treasura application is used to collect and record cash receipts from, and make payments to, Market Participants. The system is used for the market cash management functions of the IESO and interfaces directly with Lawson and the IESO's bank. The system is used to manage daily cash and create reports necessary to manage and report on the market-related cash management activities. Treasura is hosted by a third party vendor, Wall Street Systems.

5.6.15. Dispatch Data Management System (DDMS) – Contract Manager

The Contract Manager module of DDMS oversees certain physical services required for reliable operation of the electricity system, including Ancillary Services contracts (Regulation and Voltage Support)

5.6.16. Generation Cost Guarantee Tool (GCG)

The Generation Cost Guarantee Tool (GCG) is used to process and settle Market Participant claims for Real-Time Generation Cost Guarantees as set out in the Market Rules and related manuals. The tool picks up claim forms submitted by Market Participants, validates the claims, computes the appropriate settlement amounts, and sends the settlement records to CRS. The tool includes a user interface to view the claims and make adjustments, as appropriate, under the Market Rules and related manuals.

5.6.17. Control Room Operations Log (CRLOG)

The IESO control room log is the official record kept by the IESO of operating events pertaining to the IESO-controlled Grid (ICG). CRLOG serves as a communication medium to other personnel in the IESO control room and to control room support groups. It contains information on strategies used for a particular event or contingency, to identify items for reporting purposes, and to provide information for reconciliation and settlements purposes. Its contents are governed by the guidelines set out in Internal Manual 2.26: Log Entries.

5.6.18. Surveillance Data Repository (SDR)

The Surveillance Data Repository (SDR) is IESO's data warehouse which stores structured data from IESO's operational databases for the purpose of data mining and data archival. Data is extracted from the operational databases and copied to SDR on a nightly basis and information is stored for periods up to seven years.

5.6.19. Business Intelligence Toolset (BITS)/Tableau

The Business Intelligence Toolset (BITS) and Tableau is IESO's internal business intelligence tools for data queries and reporting. BITS and Tableau are used by IESO personnel for ad-hoc as well as scheduled queries of various IESO operational and analytical databases.

5.6.20. Real Time Data Historian (PI)

The Real Time Data Historian (RTDH), also referred to as PI, is responsible for storing time series information from the SCADA (Supervisory Control and Data Acquisition)/EMS (Energy Management System). The information includes telemetry information (breaker positions, voltages, power flow limits), SCADA calculations (primary demand, aggregate unit calculated breaker status) and specific application results (System Security Monitor (SSM)). The RTDH collects the information directly from the SCADA in its raw form. Data from this tool is required for calculation of payments for regulation service.

5.6.21. Market Participant Portal Access

The IESO portal is the starting point to access IESO information and software applications. Users can securely upload, share and revise data used in settlement calculations. The IESO web portal provides greater flexibility and security than a normal website and is currently used by Market Participants to access:

- Metering information via MV-WEB
- Transmission rights auction (TRA) system

- Submit and view settlement data

5.6.22. Market Participant Prudential System (MPPS)

MPPS provides Market Participants the capability to view and submit prudential scenarios and trading limits online and aims to improve accuracy of exposure estimate by utilizing a more accurate and reliable data source. It automates the process of keeping track of expiring collateral for IESO staff and provides notification to a Market Participant for expiring Letter of Credit, expiring T-Bill, collateral Call and decrease to trading limit.

5.7. IESO Information Technology Environment

5.7.1. Information & Technology Services (I&TS) Overview

The IT&S business unit consists of three relevant business areas reporting to the Vice President of I&TS and Chief Information Officer that support the IESO's overall information technology environment:

- Information Technology (IT)
- Organizational Governance Support (OGS)
- Facilities

Information Technology (IT)

IT executes the delivery of products and services through IESO personnel based on documented roles, responsibilities and performance standards or via contracts with external suppliers. The core IT division/sections are: Business Solutions, Technology Services, and IT Operations. In addition to these departments, a cross functional team of architects is responsible for establishing future technical directions and report to the Governance Committee that includes the Senior Manager, Organizational Governance Support and VP of I&TS.

Business Solutions Department

The Business Solutions Department is responsible for the development, maintenance and support of all business solutions. Their responsibilities include:

- Maintain, support and develop requirements for enhancements to Power System, Electricity Market and Corporate business solutions
- Plan replacement and major upgrades of application systems
- Manage contracts for vendors who provide support for Power System, Electricity Market and Corporate business solutions
- Provide second and third tier (external vendors) support to all application systems
- Develop web solutions for Power System, Electricity Market and Corporate business solutions
- Business Analysis Services
- Develop business processes for internal IESO business processes
- Provide integration services for business solutions acquired or developed

Technology Services Department

The Technology Services Department is responsible for the delivery, administration, and maintenance of the technical infrastructure of the IESO including:

- All server hardware/software (Unix, Linux, Windows)
- Database management system
- Desktop and laptops definition and deployment infrastructure
- Mass storage and backup infrastructure
- Local and Wide Area Networks
- Telephony and communications
- All electronic wallboard displays
- Common corporate tools such as Exchange Mail and Aspen file server

- Support of Market Participants in deploying and troubleshooting Remote Terminal Units (RTUs) and the associated front-ends and communication
- Second tier support on all of the above

The team is also accountable for capacity planning, system configuration and assisting with application deployment into the various environments.

Information Technology Operations Section

The Information Technology Operations Section is responsible for the 24x7 operation of the production environment and the IESO data centers. Their specific responsibilities include:

- 7x24 Shift Operations
- 7x24 IT Service Desk Support (Tier 1 support)
- 7x24 Data Integrity
- 7x24 IT Security Support (Monitor the virus alerts, monitor for NERC advisories and Alerts
- Incident Management
- High Level reporting on Service Desk Management.

Organizational Governance Support (OGS)

OGS provides the governance framework for the delivery and support of information systems and services in support of the IESO business plan. OGS is responsibilities for:

- Overall security policies and IT security oversight including development and coordination to implement the IT security framework (policies, standards, guidelines, procedures)
- Change, release, baseline, records and information management as well as, advising, tracking, reporting and providing metrics for each process
- Support of the IESO's business continuity management program

- Establishing and promoting project governance and project management standards and methodologies across the IESO.

Facilities Unit

The Facilities Unit is responsible for all aspects related to the operation of the physical building facilities of the IESO. Their specific responsibilities include:

- Physical Security of buildings and site (as detailed under Physical Security)
- Provision of all building electrical services including incoming utility, emergency generation and uninterruptible power for critical electrical loads
- Provision of mechanical systems including redundant HVAC for computer room, control room, electrical wing and administrative offices
- Provision of life safety systems including fire detection and suppression and coordination of first-aid/CPR training
- Office design, space planning, and facility maintenance

5.7.2. Change Management (Control Objective 16)

The IT Change Management process controls changes to the controlled live environments. Changes include: hardware, firmware, software, network, applications, systems, databases, workstations and associated documentation.

The purpose of the IT Change Management process is to ensure that changes are documented, authorized, tested and approved, and that standardized methods and procedures are used for efficient and prompt handling of requests for changes. This minimizes the impact on service quality and improves the day-to-day operation of I&TS. The process allows for handling changes that need to be expedited due to their impact level, such as emergency changes.

A set of IT documents on the IESO intranet site define the practices and management expectations to deliver changes in a controlled and quality fashion to IT managed environments. Other objectives are to:

- Ensure that all stakeholders are informed of planned changes on a timely basis and have effective ways of providing and recording their feedback on such changes
- Enable IT management reporting by maintaining a database of pertinent change management information
- Ensure that any request for change represents an acceptable balance of risk, resource effectiveness and service impact prior to implementation

The IT Change Management process includes managing and monitoring of the change process including assessment, approval, scheduling, and implementation and reporting of approved changes into the live environments. The formal IT Change Management process provides guidance on the various roles and procedures required to meet the IESO Change Management Standards.

The Change Advisory Board (CAB) is comprised of technical, operational and business representatives who examine change requests, provide recommendations and endorse changes for development based on established criteria. The CAB also provides final authorization to implement previously assessed and endorsed changes. The following is a list that describes the various CAB meeting attendees and roles:

- Business Unit representatives with the authority to endorse changes, assess impact and approve implementation and associated outages from a business perspective, as it relates to their business unit
- Change Process Manager who owns and oversees the IT Change Management process and also chairs the CAB meeting
- A dedicated Change Management Coordinator responsible for implementing and monitoring the IT Change Management process on a day-to-day basis

The Change Coordinator oversees change requests throughout the life cycle of a change and ensures all parties involved with the change request complete their obligations for the change according to budget and schedule. The implementation of the changes include other defined roles including:

- A Change Implementer who assumes the responsibility to implement the change or oversees the implementation of the change and ensures that all parties involved with the Request For Change (RFC) complete their obligations for the change according to budget and/or schedule
- A Change Verification Tester who upon implementation of the change verifies that the change implemented functions as expected.

Testing or verification plans and results are prepared and documented for non-emergency changes, and takes into account the nature of the changes and their effects on availability and continued security as part of the testing and review considerations.

The documentation related to a change is retained. This documentation includes descriptions, scheduled and actual completion windows, implementation plans/results, required approvals, and testing/verification plans/results.

Impact assessments are performed and documented as per the Impact Assessment Guide and are a mandatory requirement of the IT Change Management process. Team Leads (or designates) review and assess the potential impact of their change against a predetermined list of categories. Approval is documented on an Impact Assessment Sign off Sheet and is presented to the Change Management Coordinator before the changes are submitted to the CAB for approval.

IT changes are scheduled taking into account the ability for the business to support the change, and where Market Participant interfaces are involved; external limitations are also taken into account. Changes are implemented in such a way as to ensure minimum service disruption and maximum communication. Contingency plans are developed and tested in the event that a change fails and must be restored to its previous state.

Emergency changes that are initiated in the off hours are documented the next business day and approved in a timely manner. The documentation would include a retroactive impact assessment, approvals, and post implementation review to ensure that the change is implemented correctly and to perform validation that the change is working as intended.

Critical production systems are monitored for changes to the operating systems and critical application files. A process is in place to categorize changes and compare them to planned and documented changes.

Where possible, individual changes are grouped into packaged implementation releases to minimize risks of business impacts, and to avoid redundancy of effort. This implementation packaging includes software, hardware, network and related documentation, all of which are subject to IT Change Management process for final approval.

An IT Release Coordinator is charged with coordination of the IT Release from implementation planning through to post implementation review. The Releases are categorized based on the type of impact that the release has on the Market Participants. A release calendar is prepared and published for each year. The calendar sets out dates for communication and implementation.

The IESO has the following control objective related to change management:

- Controls provide reasonable assurance that changes to critical production systems are documented, authorized, tested, approved, and properly implemented.

5.7.3. Logical and Physical Access (Control Objectives 14 and 17)

5.7.3.1. Logical Access

OGS is responsible for establishing and maintaining a framework of information technology security policies, standards, and guidelines. Other departments within I&TS are responsible for the design, implementation, and day-to-day management of technologies and processes to ensure that IT security controls are delivered, maintained and monitored consistent with established architectures, policies and standards.

OGS provides management oversight of information security related plans, arrangements, and processes for compliance with policies and standards, and reports identified issues to the CIO and VP I&TS. To facilitate this oversight, OGS maintains and operates certain “special security systems” (such as intrusion detection systems and forensic analysis systems) independently from departments responsible for day-to-day operations of information systems.

A mandatory security and confidentiality awareness program is in place for all employees.

Procedures are in place to govern the granting and revoking of permissions for access to IESO facilities and information processing assets. Business or system role or privilege stewards approve requests for access prior to granting of the access. These procedures are designed and operated to establish a separation between the granting of access permissions and the implementation of those permissions. Procedures are in place to ensure timely revocation of access permissions when such permissions are no longer necessary or appropriate and for staff departures.

Privileged access to operating system, database and application functions is limited to appropriate individuals by following the documented process for granting and revoking access. Also, the IESO monitors access violations and attempts to detect possible intrusion to servers and applications.

Procedures are in place to undergo a periodic review of all individuals with access privileges on critical production systems. The results of the review are approved by the business or system role or privilege stewards. Any discrepancies identified are resolved using the general process for granting and revoking access. The same process is followed for medium and high risk end user computing tolls that are used to support the settlements process.

The IESO performs background checking (including a criminal record check and review by the Canadian Security Intelligence Service) of all new hires and of all contractors and consultants provided with unescorted physical access to IESO facilities or logical access to systems.

An information security awareness program has been established which is mandatory for all employees.

Remote (logical) access to IESO systems requires users to authenticate using two-factor authentication based on a token and a memorized Personal Identification Number (PIN) or password. The IESO uses a Virtual Private Network (VPN) solution to provide a secure tunnel through which authorized staff and vendors may access the internal network from the internet. Traffic coming through that tunnel is subject to 128 bit encryption.

Additionally, access to operating systems, databases, application software, and end-user computing tools that support the settlement process is controlled through the use of user accounts and passwords. Standards have been established governing password complexity and lifetimes. General configuration of settings on the operating systems and databases are used to force compliance where technically feasible. Access to install applications on IESO workstations is limited to privileged IT staff.

System administrators are responsible for information system configuration and day-to-day administration. Security related logs are collected by, and stored in, a centralized logging facility which provides a high degree of assurance that the integrity of logs cannot be compromised. Periodic security related reviews of logged events are conducted.

Network and firewall devices are implemented to prevent unauthorized access to IESO systems/networks from the internet. Firewall rule changes are controlled as per the approved change management process. Only authorized individuals have access to perform firewall systems administration and maintenance.

Intrusion protection provisions are in place on the network segment between the border router and the main firewall to detect and log suspicious activity originating from the internet. Intrusion detection system agents are also deployed on various high value hosts to facilitate intrusion detection. Software is also used on critical systems to monitor key files for unauthorized changes.

The IESO employs content scanning to detect and, where possible, prevent the presence of malicious code within its network and market systems. Content scanning is performed in real time on inbound e-mail, web-page content, on user workstation file access attempts and on most servers. Content scanning for "extended threats" (adware/spyware) is performed on user workstations on a periodic basis. On detection, malicious software is removed. An event where there is a detection of viruses, worms, or trojans on IESO workstations and servers is formally investigated and reported to management for further action as appropriate. Only authorized individuals have access to perform anti-virus systems administration and maintenance.

5.7.3.2. Physical Access

The Facilities Unit at the IESO is responsible for managing all aspects of physical security to its physical assets including property and buildings. This includes access to the IESO's backup operations center owned by Sungard. Access control measures are applied to all employees, contracted staff and vendors through the use of a centralized electronic card access system. The IESO has implemented a layered approach to ensure that multiple levels of authorization are required to gain entry to increasingly restricted areas within the IESO buildings including entry and exit points of sensitive areas within the facilities and mantraps to control access to the control room. On a regular and periodic basis, historical logs are reviewed and access rights to all areas are reaffirmed and adjusted accordingly.

Critical areas of the IESO's facilities are monitored by the IESO`s Security Team through CCTV cameras 24x7 which is archived for subsequent analysis, if required. Surveillance cameras complement the access control system in providing visual confirmation of physical access. Cameras are strategically located.

The IESO's Clarkson property is further secured by a combination of vehicle access control and a gated perimeter.

The IESO has the following control objective related to logical and physical access:

- Controls provide reasonable assurance that access within applications to update or modify data is restricted to appropriate personnel.
- Controls provide reasonable assurance that logical access to critical production systems and data, and physical access to computer equipment is restricted to properly authorized individuals.

5.7.4. Backup & Recovery (Control Objective 18)

The IESO's Tape Backup and Restore system provides enterprise wide file backup and restoration services. This system is integrated into the mass storage sub-systems using the storage area network (SAN) in order to provide high-speed backup/restore services. IESO maintains a master list of system components that is assessed by management to ensure that all critical system components are backed-up and can be recovered.

The IESO operates redundant backup servers, one each at the primary site and the backup operations center site. Additionally, all critical data is replicated in real-time from the primary site to the backup site. Requirements for the recovery of business functions following a contingency are established by the leaders of each IESO business unit. Business units establish and exercise plans to meet these requirements. Redundancy for critical information systems is provided at a physically remote backup site. The ability to operate those redundant systems is tested periodically.

In the event that the IESO has to work remotely from shared workstations due a catastrophic event or as part of Business Continuity training at a third-party service provider (e.g. SunGard), representatives from IESO will observe on site to verify that shared workstations have been scrubbed and will also receive an email confirmation from the third-party that the workstation have been scrubbed.

Only authorized personnel have access to offline storage, and back-up data, systems and media.

The IESO has established policies related to data retention and disposal of confidential settlement information that in accordance with Market Rules retention requirements.

The IESO has the following control objective related to backup and recovery:

- Controls provide reasonable assurance that critical production systems and related data supporting settlement processes are properly backed-up so that they can be recovered in the event of a system outage or data integrity issue.

5.7.5. Job Scheduling (Control Objective 19)

Batch processing jobs required for supporting business and IT processes are scheduled and documented. These jobs are subject to change control. Tier 1 support monitors and reviews the result of these jobs. Any changes to the batch processing jobs are processed through the IT Change Management process.

Job scheduling log results are reviewed by system operators and exceptions are followed up. Job failures are resolved in the Problem & Incident Management processes.

Management reviews recorded processing deviations and errors bi-weekly and ensures appropriate follow-up actions have been assigned and are being undertaken.

The IESO has the following control objective related to job scheduling:

- Controls provide reasonable assurance that programs are executed as planned and that deviations from scheduled processing are identified and resolved in a timely manner.

5.7.6. Incident Management (Control Objective 20)

The IESO has implemented a formal incident management (malfunctions) process based on the ITIL framework. These processes provide the framework to prioritize service failures, assign and escalate to designated IT support, record investigation and resolution. The processes also provide guidance on how IT personnel are required to create incidents based on IT issues detected from various systems monitored by the IT department. The incident management process has been documented in policy and procedural documentation which are available on the IESO website.

The IESO maintains 24x7 on-site shift IT coverage. IT Shift Control Engineers (SCEs) monitor and support the operation of the critical IT applications and infrastructure. This group uses centralized monitoring to support this function. This central tool receives “triggers” from various sources such as locally installed agents on servers. This level of support is referred to as Tier 1.

Application and infrastructure specialists provide support procedures to allow Tier 1 support to recover from “known errors” and to manually health check the systems. Where Tier 1 is unable to recover a failed service, the incident is escalated to Tier 2, an application or infrastructure specialist who is on-call 24x7 for all critical systems. Tier 3 support is also available from some Service Providers. In addition, if incidents of certain severity remain outstanding beyond documented limits there is informational escalation through management up to the CEO.

Tracking and management of all incidents are done using the IESO's ticketing system, and may invoke the change management process to take correction actions required to resolve IT incidents.

Service Level Agreements have been established where business users have determined the required reliability, and availability of the applications and infrastructure. These agreements provide the guidelines for determining the priority and response time to loss of service incidents. IT Management regularly meets to review significant processing deviations and errors.

The IESO has the following control objective related to problem and incident management:

- Controls provide reasonable assurance that IT operations incidents are identified, recorded, responded to, resolved or investigated, reviewed, and analyzed in a timely manner.

5.7.7. Third Party Service Provider Monitoring (Control Objective 21)

IT management reviews the scope, control objectives, and control descriptions of the Wallstreet Treasura System service organization report, on an annual basis, to ensure the report identifies all internal controls relevant to change management, logical and physical access management, backup and recovery, job scheduling, and problem and incident management. Furthermore, the audit opinion and exceptions are reviewed to determine if follow-up is required with Wall Street Systems management to identify compensating controls, if necessary, to mitigate associated risks.

The IESO has the following control objective related to third party service provider monitoring:

- Controls provide reasonable assurance that third party services are monitored for the design and operating effectiveness of the third party services' controls.

5.8. Market Participant Control Considerations

The IESO's Settlement Operations were designed with the assumption that certain procedures and controls would be in existence or implemented by Market Participants. In certain situations, the application of these procedures and controls is necessary to achieve certain control objectives included in this report.

This sub-section describes those additional policies, procedures, and controls that should be in operation at the Market Participant to complement the managed services and corresponding controls. The user auditor should consider whether the following controls have been placed in operation at the Market Participant. The list of Market Participant control considerations presented below does not necessarily represent a comprehensive set of all the procedures and controls that should be employed by Market Participant.

Control Objectives	Market Participants Control Considerations
1	Market Participants are responsible for ensuring the complete, accurate and timely submission of their corporate (e.g. name change, banking information) and metering registration information via Online IESO.
	Market Participants who are not also MSPs are required to enter into an agreement with MSPs. MSPs are responsible for submitting complete, accurate and timely documentation and data for the registration of meters, and meter data edit proposals.
	Market Participants are responsible for ensuring that the metering data provided is complete, accurate and timely.
2	Market Participants are responsible for ensuring the complete, accurate and timely submission of their corporate (e.g. name change, banking information) and metering registration information via Online IESO.

	Market Participants who are not also MSPs are required to enter into an agreement with MSPs. MSPs are responsible for submitting complete, accurate and timely documentation and data for the registration of meters, and meter data edit proposals.
	Market Participants are responsible for retrieving metering data, settlement statements and data that will support reconciliation of their settlement statements.
	Market Participants are responsible for providing complete, accurate and timely resolution of meter trouble reports.
3	Market Participants are responsible for ensuring the complete, accurate and timely submission of all market data (e.g. bids, offers, forecasts, schedules) for the energy and operating reserve markets.
5	Market Participants are responsible for tracking the amount of ancillary services they provide and reconciling their data with IESO records when the IESO communicates with them to confirm resources and/or quantities. Market Participants will notify the IESO in a timely manner of any discrepancies found.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of data to support ancillary service settlement calculations.
	Market Participants are responsible for retrieving metering data, settlement statements and data that will support reconciliation of their settlement statements.
	Market Participants are responsible for ensuring timely and complete communication of any changes to requirements which may impact the processing of Generation Station Service Rebate (GSSR).
	Market Participants are responsible for ensuring that Real-Time Generation Cost Guarantee claims are complete, accurate, submitted in a timely manner, and appropriately authorized.

	Market Participants are responsible for ensuring the complete, accurate and timely submission of all market data (e.g. bids, offers, forecasts, schedules) for the energy and operating reserve markets.
6	Market Participants are responsible for tracking the amount of ancillary services they provide and reconciling their data with IESO records when the IESO communicates with them to confirm resources and/or quantities. Market Participants will notify the IESO in a timely manner of any discrepancies found.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of data to support ancillary service settlement calculations.
	Market Participants are responsible for retrieving metering data, settlement statements and data that will support reconciliation of their settlement statements.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of Global Adjustment information, as required by the IESO.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of information to the IESO with respect to adjustments required under Bill 100.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of OPG Rebate distribution and return information, as required by the IESO.
	Market Participants are responsible for ensuring the complete, accurate and timely submission of data to support ancillary service settlement calculations.
	Market Participants are responsible for providing complete, accurate and timely resolution of meter trouble reports.
8	Market Participants are responsible for reviewing their settlements statements, invoices and payments from the IESO and advising the IESO of any discrepancies.

	Market Participants are responsible for ensuring the complete, accurate and timely submission of a Notice of Disagreement to the IESO, as required by the IESO.
9	Market Participants are responsible for ensuring the complete, accurate and timely submission of their corporate (e.g. name change, banking information) and metering registration information via Online IESO.
	Market Participants are responsible for reviewing their settlements statements, invoices and payments from the IESO and advising the IESO of any discrepancies.
10	Market Participants are responsible for reviewing their settlements statements, invoices and payments from the IESO and advising the IESO of any discrepancies.
13	Market Participants are responsible for ensuring the complete, accurate and timely submission of a Notice of Disagreement to the IESO, as required by the IESO.
17	Market Participants are responsible for ensuring that their workstations comply with all applicable technical requirements as required by the IESO.
	Market Participants are obliged through the Market Rules to ensure their credentials are managed securely.
	Market Participants are responsible for ensuring that controls over physical and logical access to the IESO's information systems through interfaces with terminals at the Market Participants location are established, monitored and maintained.

Additional detail regarding the IESO's control procedures is included in the following section of this report "Description of Control Objectives, Controls, Tests and Results of Tests" to eliminate the redundancy that would result from providing this information in this section and repeating it in the following section. Although the control objectives and control procedures are included in the following section, they are, nonetheless, an integral part of the IESO's description of the settlement operations system.

Description of Control Objectives, Controls, Tests and Results of Tests

Purpose and Objectives of the Service Auditor Examination

In planning the nature, timing and extent of our testing of the controls specified by the IESO, we considered the aspects of the IESO's control environment, risk assessment processes, information and communication and management monitoring procedures and performed such procedures as we considered necessary in the circumstances. These tests included the following:

- Inspected corporate HR documentation and determined that that all employees are required to sign and adhere to the Code of Conduct as a condition of employment and are required to undergo annual re-affirmation.
- For a sample of employees, inspected evidence that the Code of Conduct annual re-affirmation was signed.
- Inspected corporate HR documentation and determined that all employees, vendors and third parties are required to sign a confidentiality agreement prohibiting any disclosure of information to which they have access.
- Inspected corporate HR documentation and determined that Employee Development Plans are established and reviewed for all employees on an annual basis.
- Inspected the IESO Enterprise Risk Management (ERM) Assessment and determined that it documents risks, overall impact and lays out mitigation plans as required.
- For a sample of quarters, inspected the IESO ERM Assessment to determine that it documented risks, overall impact and lays out mitigation plans as required.
- Inspected the IESO Internal Audit plan and findings and determined that there are various audits that are performed throughout the year and its findings are documented and communicated to the Audit Committee of the Board of Directors.

The descriptions of the control objectives and related controls for systems and Applications on the pages that follow have been specified by, and are the responsibility of the IESO. The testing performed by Ernst & Young and the results of the tests are the responsibility of the service auditor.

Procedures for Assessing Completeness and Accuracy of Information Produced by the Entity (IPE)

For tests of controls requiring the use of Information Produced by the Entity (IPE), procedures were performed to assess the reliability of the information, including completeness and accuracy of the data or reports, to determine whether the information can be relied upon in the examination procedures. This includes IPE produced by the Independent Electricity System Operator and provided to user entities (if relevant and defined as part of the output control objectives), IPE used by the Independent Electricity System Operator management in performance of controls (i.e., periodic review of user listings), and IPE used in the performance of our examination procedures.

Based on the nature of the IPE, a combination of the following procedures were performed to address the completeness and accuracy of the data or reports used: (1) inspect source documentation relating to the IPE, (2) inspect the query, script, or parameters used to generate the IPE, and/or (3) agree data between the IPE and the source.

Control Objective 1: Registration of Meters

Controls provide reasonable assurance that Market Participant contract relationship information and registered new or updated meters are recorded in the IESO's systems completely, accurately, and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
1.01	Initial Market Participant contract relationship information is entered into IESO's Customer Data Management System (CDMS) by the Market Participant using On-Line IESO. Updates to Market Participant contract relationship information is provided on forms and entered into CDMS by Settlement staff via data RFC. Settlement staff checks that the data was entered correctly.	Inquired of Settlement personnel to determine whether changes to Market Participant contract relationship information is provided on forms and entered into CDMS via data RFC and that Settlement staff checks that the data was entered correctly. Inspected a sample of updates to Market Participant contract relationship information submitted to the IESO to determine whether Settlement staff entered Market Participant contract relationship information from registration forms into CDMS, and whether the contract relationship information was then reviewed within CDMS for accuracy by another Settlement staff member.	No deviations noted.
1.02	Settlement staff reviews the following documentation submitted by MSPs on behalf of Metered Market Participants, for conformance with IESO requirements: · Single Line Diagram (SLD), Measurement Error Correction Register (MEC), Site Specific Loss Adjustment Register (SSLA), Emergency IT Restoration Plan (EITRP), Alternative Metering Installation Standard	Inquired of Settlement personnel to determine whether Settlement staff review meter registration documents submitted by the MSP for conformance with IESO requirements. Inspected a sample of meter registrations submitted to the IESO to determine whether: · The appropriate meter registration documents (SLD, MEC, SSLA, EITRP, AMIS, DOC, and MIRT files) were submitted by the MSP. · The MEC and SSLA register were signed-off by a Registered Professional Engineer. · The Engineering Unit Report for the metering installation was signed-off by the MSP.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
	(AMIS)/Declaration of Compliance (DOC) and MIRT file (MV-90 master file). The MIRT file is entered into the Meter Data Acquisition System (MDAS) and upon successful completion of the end to end test, an Engineering Unit Report is provided to the MSP for approval. Settlement staff checks that: · The above documents have been submitted by the MSP. · The SSLA and MEC registers have been signed by a Registered Professional Engineer. · The Engineering Unit Report for the metering installation has been approved by the MSP.		
1.03	Settlement staff reviews the Totalization Table form submitted by the Meter Service Providers for accuracy. Settlement staff enters the information into the Meter Data Management System (MDMS) and issues Site Registration Report (SRR) to the Meter Service Provider for approval.	Inquired of Settlement personnel to determine whether Settlement staff review the Totalization Table form submitted by the Meter Service Providers for accuracy, and that Settlement staff enter the information into MDMS and issue Site Registration Reports (SRR) to the Meter Service Provider for approval. Inspected a sample Totalization Table form submitted by the MSP to determine whether the review was performed by the	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
		Settlement staff before the information was entered into the MDMS, and the SRR was issued to the MSP for approval.	
1.04	Settlement staff reviews Meter Installation Commissioning Reports submitted by the Meter Service Providers for conformance with IESO accuracy and completeness requirements.	Inquired of Settlement personnel to determine whether Settlement staff review the Meter Installation Commissioning Reports submitted by the Meter Service Provider for conformance with IESO accuracy and completeness requirements. Inspected a sample Meter Installation Commissioning Report submitted by the Metering Service Provider to determine whether the review was performed and accepted by Settlement staff.	No deviations noted.
1.05	Settlement staff conducts annual audits of a sample of metering installations to determine that metering installations are registered in accordance with the Market Rules. IESO issues a report which identifies findings and associated actions. · Audits are “Closed” when all findings have been successfully addressed within specified timeline. · Audits are “Closed with Observations” when findings cannot be addressed within specified timelines. Outstanding action items are tracked using On-Line IESO	Inquired of Settlement personnel to determine whether Settlement staff conduct annual audits of a sample of metering installations to determine that they are registered in accordance with Market Rules. Inspected a sample annual audit report to determine whether the metering installations were registered in accordance with the Market Rules and whether audit findings were have been successfully addressed within the specified timeline or “Closed with Observations” and tracked using the On-Line IESO for the remediation of outstanding actions. Inspected a sample metering installation and determined that the annual audit had been performed by Settlement staff.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
	Conformance Monitoring process to ensure completion of all non-conformances related to metering installations.		
1.06	On a monthly basis, Contributor Management Registration submissions provided by the Demand Response Market Participant are reviewed by Settlement staff for conformance with the contributor management registration requirements of the DR Auction/Pilot program.	Inquired of Settlement personnel to determine whether Contributor Management Registration submissions provided by the Demand Response Market Participant are reviewed by Settlement staff for conformance with the contributor management registration requirements of the DR Auction / Pilot program. Inspected a sample of months to determine whether Settlement staff are reviewing the Contributor Management Registration submissions for conformance with the contributor management registration requirements.	No deviations noted.

Control Objective 2: Transmission of Metering Data

Controls provide reasonable assurance that metering data used in settlements calculations is received from registered meters and processed in the IESO's system completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
2.01	Metering data is collected and validated from registered meters by the Meter Data Acquisition System (MDAS) based on pre-defined system parameter settings, master file settings and a programmed task schedule.	Inquired of Settlement personnel to determine whether MDAS system receives metering data from registered meters based on pre-defined system parameter settings and a programmed task schedule. Inspected the MDAS system parameter settings to determine whether the pre-defined system parameter and programmed task schedules settings are set up to identify possible transmission anomalies or errors.	No deviations noted.
2.02	Settlement staff checks Meter Data Management System (MDMS) Work Queue Reports daily to identify meter data files that failed to transfer from MDAS to MDMS. Problems, if any, are investigated and resolved.	Inquired of Settlement personnel to determine whether Settlement staff check that meter data collected in MDAS is transferred to the MDMS system to identify potential data integrity problems, and whether errors are investigated and resolved. Inspected a sample of MDAS failed loader reports to determine whether the settlement staff monitor the MDMS Work Queue Reports daily and whether identified problems were investigated and resolved by Settlement staff.	No deviations noted.
2.03	The MDMS validates metering data based on assigned validation groups and global and local validation threshold settings. Work queues identify data that has failed validation.	Inquired of Settlement personnel to determine whether MDMS and the related end user computing tool validate metering data based on pre-defined system parameter and master file settings, and flags data that has failed validation. Inspected the MDMS system parameter and master file settings to determine whether the settings were set up to identify possible transmission anomalies or errors. Inspected a sample work queue to determine whether failed validations were captured completely and accurately.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
2.04	Settlement staff reviews daily reports of meter data that have failed validation (e.g. energy tolerances, power outages, voltage/current checks, main vs. alternate meter comparisons and deviations in load profile). They analyze data, perform edits and issue MTRs to MSPs to resolve issues.	Inquired of Settlement personnel to determine whether Settlement staff review daily reports of meter data that has failed validation, and investigates and resolves failures. Inspected a sample of failed validation reports to determine whether Settlement staff review daily reports of meter data that has failed validation, and investigates and resolves failures.	No deviations noted.
2.05	On a daily scheduled basis the MDMS automatically estimates missing data intervals. The hierarchy of estimates performed are: alternative meter data where it exists, linear interpolation for gaps less than an hour, previous three weeks (five if contains stat holiday) of historical metering data for all other situations.	Inquired of Settlement personnel to determine whether MDMS system auto estimates missing data intervals when interrogation has failed for the day based on linear interpolation for gaps less than an hour, alternative meter data where it exists, or on the previous three weeks of historical metering data for other situations. Inspected a sample Automatic Editing Report to determine whether the MDMS automatically estimates missing data intervals based on the hierarchy of estimates on a daily basis.	No deviations noted.
2.06	On a daily scheduled basis the meter trouble reporting system automatically: • issues a meter trouble report (MTR) for failed interrogations after 2 consecutive days to Metered Market Participants (MMPs) and Meter Service Providers (MSPs); and • updates daily the Communication History for all open Communication MTRs.	Inquired of Settlement personnel to determine whether the Meter Trouble Reporting system automatically creates and issues a Meter Trouble Report to metered Market Participants and MSPs for failed interrogations and for a set of validation failures. Inspected a sample failed meter interrogation to determine whether the system automatically issues a MTR for failed interrogations and updates the daily Communication History for all open Communication MTRs.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
2.07	Settlement staff assess failed validations, perform an edit if necessary, and if needed manually issue a MTR for further issue resolution or edit confirmation to MMPs and MSPs.	Inquired of Settlement personnel to determine whether Settlement staff assess failed validations and perform, if necessary, an edit, a manual MTR or an edit confirmation to MMPs and MSPs. Inspected a sample of failed validations to determine whether Settlement staff assess failed validations and perform if necessary, an edit, a manual MTR or an edit confirmation to MMPs and MSPs.	No deviations noted.
2.08	Settlement staff review and assess MSP's response, edit proposals and submitted data files before entering them into the MDAS. They ensure the edits/files are uploaded into MDMS before closing the MTR with their final resolution comments.	Inquired of Settlement personnel to determine whether Settlement staff review and assess MSP's response, edit proposals, and submitted data files before entering them into the MDAS and closing the MTR with their final resolution comments. Inspected a sample of MTRs to determine whether Settlement staff review and assess the MSP's response, edit proposals, and submitted data files before entering them into the MDAS and closing the MTR with their final resolution comments.	No deviations noted.
2.09	MDMS creates a new version of raw data after each upload from MDAS and a new version of validated data once all validation tests are passed. Using the latest version of validated meter data, calculated meter data is computed on a scheduled basis and Current, Initial, Preliminary and Final calculation results are stored in MDMS for a minimum of 36 months. Post Final calculations are performed on an ad hoc basis and stored in MDMS.	Inquired of Settlement personnel to determine whether MDMS creates a new version of raw data after each upload from MDAS and a new version of validated data once all validation tests are passed. Inspected a sample MDAS data upload to determine whether MDMS creates a new version of raw data after each upload from MDAS and a new version of validated data once all validation tests are passed.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
2.10	Using On-Line IESO, Measurement Data submissions are provided by the Demand Response Market Participant on a scheduled basis and reviewed by Settlement staff for conformance with the measurement data submission requirements of the DR Auction/Pilot program.	Inquired of Settlement personnel to determine whether Measurement Data submissions are provided by the Demand Response Market Participant on a schedule basis and reviewed by Settlement staff for conformance with measurement data submission requirements. Inspected a sample of Measurement Data submissions to determine whether Settlement staff review the submissions for conformance with submission requirements.	No deviations noted.

Control Objective 3: Bids & Offers/ Energy Price & Schedule

Controls provide reasonable assurance that bids and offers are received and processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
3.01	The Market Information Management (MIM) system verifies that the required bid and offer data fields are complete and has been submitted within a valid timeframe. The system also notifies the Market Participants of the status of the submission.	Inquired of Ex-Post personnel to determine whether the MIM system verifies the required bid and offer data fields are complete and the data file has been submitted within a valid timeframe and whether MIM notifies the Market Participants of the status of the submission. Re-performed the bid and offer submitted to determine whether the MIM system checks the required data fields are complete and has been submitted within the valid timeframe. Re-performed the bid and offer submitted to determine whether MIM notified the Market Participant of the status of the submission.	No deviations noted.
3.02	The MIM system copies missing 5-minute market clearing price and schedules from the last DSO-calculated MCP's and schedules. On a daily basis, Ex-Post staff reviews reports listing ADMIN events, such as the HOEP report. Price and schedule anomalies are investigated and resolved.	Inquired of Ex-Post personnel to determine whether MIM calculates the HOEP based on the 5-minute MCP and on a daily basis, Ex-Post staff reviews the report listing ADMIN events and investigates and resolves any anomalies. Inspect a sample of ADMIN events to determine whether Ex-Post staff review the report listing ADMIN events and investigates and resolves any anomalies.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
3.03	The MIM system transfers market clearing price data to the Commercial Reconciliation System (CRS) for subsequent settlement processing. If errors are generated during the settlement processing an email is sent to Ex-Post to investigate. Any corrections made in MIM resulting from the investigation are reported back to Settlements by email.	Inquired of Settlement personnel to determine whether MIM transfers the MCP data to CRS for subsequent settlement processing and whether Ex-Post staff perform investigations and make corrections in MIM in the event of an error. Re-perform the MIM system transfer to determine whether the MIM system transfers market clearing price data to the CRS for subsequent settlement processing. Inspected a sample of MIM system transfer errors to determine whether Ex-Post investigates errors generated during the system processing and corrections are reported back to Settlements by email.	No instances of MIM system transfer errors of market clearing price to CRS occurred during the period; therefore, could not test operating effectiveness.
3.04	The MIM system transfers data necessary for the settlement of congestion management settlement credits (CMSC) and the intertie offer guarantee (IOG) to CRS for subsequent settlement processing. If errors are generated during the settlement processing and email is sent to Ex-Post to investigate. Any corrections made in MIM resulting from the investigation are reported back to Settlements by email.	Inquired of Settlement personnel to determine whether the MIM system transferred the data necessary for the settlement of CMSC and IOG to CRS for subsequent settlement processing and whether Ex-Post staff perform investigations and make corrections in MIM in the event of an error. Re-perform the MIM system transfer to determine whether the MIM system transfers data necessary for the settlement of CMSC and IOG to CRS for subsequent settlement processing. Inspected a sample of errors generated during settlement processing to determine whether Ex-Post staff perform investigations and make corrections in MIM and corrections made are reported back to Settlements by email.	No instances of MIM system transfer errors of CMSC and IOG to CRS occurred during the period; therefore, could not test operating effectiveness.

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	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
3.05	Ex-Post staff on a daily basis review MIM system reports listing missing prices and schedules from the previous day's market activities. Discrepancies are investigated and resolved.	Inquired of Ex-Post personnel to determine whether, on a daily basis, Ex-Post staff review MIM system reports listing missing dispatch data, missing prices and schedules from the previous day's market activities and whether discrepancies are investigated and resolved. Inspected a sample of MIM system reports listing missing dispatch data, missing prices and schedules from the previous day's market activities to determine whether Ex-Post staff reviewed the report listing on a daily basis and whether any discrepancies were investigated and resolved.	No deviations noted.
3.06	The Section Head - Control Room Support or designated alternate reviews and approves all MIM data changes prior to sending to Settlements for entry in CRS.	Inquired of the Section Head, Control Room Support to determine whether the Section Head, Control Room Support reviews and approves all MIM data changes prior to sending to Settlements for entry in CRS. Inspected a sample of MIM data changes to determine whether the Section Head, Control Room Support reviews and approves the changes prior to sending to Settlements for entry in CRS.	No deviations noted.

Control Objective 4: Transmission Rights Auction

Controls provide reasonable assurance that Transmission Rights Auction data in the Commercial Reconciliation System is received from the TRA system and is processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
4.01	Finance informs SA of successful Transmission Rights Auction results for which payment was not received. SA staff mark these auction results as revoked in the TRA tool, then SA Section Manger (or MFI Team Lead during TRA process transition period) verifies and signs off that the data was entered correctly.	Inquired of Settlement personnel to determine whether Finance informs MFI of successful Transmission Rights Auction results for which payment was not received, and whether MFI staff mark these auction results as revoked in the TRA tool, and then MFI Team Lead verifies and signs off that the data was entered correctly. Inspected a sample of successful Transmission Rights Auction results for which payment was not received and determined whether the auction results were revoked by MFI staff and verified and signed off by the MFI Team Lead.	No instances of successful Transmission Rights Auctions results for which payment was not received occurred during the period; therefore, could not test operating effectiveness.
4.02	The Transmission Rights Auction (TRA) system uploads transmission rights ownership and auction results to the CRS for subsequent settlement processing.	Inquired of Settlement personnel to determine whether the TRA system uploads transmission rights ownership and auction results to the CRS for subsequent settlement processing. Re-performed the TRA system uploads to determine whether the TRA system uploads transmission rights ownership and auction results to the CRS for subsequent settlement processing.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
4.03	Settlement staff compares the TRA system-generated Auction Round and Auction Settlement reports to check that the data uploaded into the CRS is complete, accurate, and timely. Discrepancies, if any, are investigated and resolved.	Inquired of Settlement personnel to determine whether Settlement staff compares the TRA system-generated Auction Round and Auction Round Settlement reports to check that the data uploaded into the CRS is complete, accurate and timely and determine whether discrepancies, if any, are investigated and resolved. Inspected a sample of Auction Round and Auction Round Settlement reports to determine whether a review was performed by Settlement staff to check the data uploaded into the CRS is complete, accurate and timely and to determine whether discrepancies, if any, were investigated and resolved.	No deviations noted.

Control Objective 5: Settlement Input and Claim Validation Data

Controls provide reasonable assurance that data used in semi-automated and manual calculations are received from Market Participants and processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.01	Market Participant data used as inputs to manual settlement activities/calculations are submitted via online forms and accessed as read-only sources.	Inquired of Settlement personnel to determine whether Market Participant data used as inputs to manual settlement activities/calculations are submitted via online forms and provided as read-only sources. Re-performed a sample manual settlement calculation to determine whether the Market Participant data used as inputs to the calculations were submitted via online forms and accessed as read-only sources.	No deviations noted.
5.02	Market Participants submit data via online IESO portal communities, which is only accessible by Settlements in read-only format. Market Participants' inputs from portal communities are translated into MLIs and repeated back to the participant in the settlement statements.	Inquired of Settlement personnel to determine whether Market Participant data used as inputs to manual settlement activities/calculations are submitted via online IESO portal communities in read only format. Re-performed a sample manual settlement calculation to determine whether Market Participants' inputs were translated into MLIs.	No deviations noted.
5.03	For medium and high risk end-user computing (EUC) tools, Settlement data used as inputs to manual settlement activities/calculations provided by internal sources are accessed from read-only sources.	Inquired of Settlement personnel to determine whether, for medium and high risk EUC tools, Settlement data used as inputs to manual settlement activities/calculations provided by internal sources were read-only sources. Re-performed a sample of manual settlement calculations for medium and high risk EUC tools to determine whether Market Participant data used as inputs to manual settlement activities/calculations provided by internal sources were accessed from read-only sources.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.04	For medium and high risk end-user computing (EUC) tools, Settlement data used as inputs to manual settlement activities/calculations are extracted from read-only IT-supported databases using queries. Queries are re-executed independently when check tools are used.	Inquired of Settlement personnel to determine whether Settlement data used as inputs to manual settlement activities/calculations are extracted from read-only IT-supported databases using queries and queries are re-executed independently when check tools are used. Re-performed a sample of manual settlement calculations to determine whether settlement data used are extracted from read-only IT-supported databases and that queries were re-executed independently when check tools are used.	No deviations noted.
5.05	For medium and high risk EUC tools, Settlement data used as inputs to manual settlement activities/calculations are provided by IT-executed queries as read-only files.	Inquired of Settlement personnel to determine whether, for medium and high risk EUC tools, Settlement data used as inputs to manual settlement activities/calculations are provided by IT-executed queries as read-only files. Re-performed a sample manual settlement calculation to determine whether, for medium and high risk EUC tools, settlement data used were provided by IT-executed queries as read-only files.	No deviations noted.
5.06	The IESO negotiates formal Ancillary Service agreements with Market Participants that determine the monthly payments/charges. The Ancillary Service agreements are executed by the IESO in accordance with the Organizational Authority Register (OAR), and by the Market Participant.	Inquired of Ex-Post personnel to determine whether Ex-Post staff reviews negotiated formal procurement agreements with Market Participants that determine the charges that are to be paid monthly. Inspected a sample of formal procurement agreements to determine whether the monthly charges were accurately used in the EUC tools and appropriately signed off by the IESO and the Market Participant.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.07	On a daily and monthly basis, the Ex-Post staff confirms the generator source and the quantity of Regulation Service provided for each hour of the day with the service providers using the DDMS tool and notes in the CROW Log. Differences are investigated and adjustments made prior to sending data to Settlements.	Inquired of Ex-Post personnel to determine whether Ex-Post staff confirm the generator source and quantity of Regulation Service provided for each hour of the day with the service provider on a daily and monthly basis. In addition, inquired of Ex-Post personnel to determine whether differences, if any, are investigated and adjustments were made prior to sending data to Settlements. Inspected a sample of generator source and quantity confirmation e-mails to determine whether the source and quantity provided for each hour of the day from the service provider daily and monthly was confirmed.	No deviations noted.
5.08	Each day, control room staff confirms the generator source and the quantity of Reactive Support and Voltage Control service provided (Condense and Speed-No-Load information including units, start/end times and start-ups required) with the service providers using the DDMS tool and notes within the CROW Log. Differences are investigated and adjustments made prior to sending data to Settlements.	Inquired of Control Room personnel to determine whether Control Room staff on a daily basis confirm the generator source and the quantity of Reactive Support and Voltage Control service provided (Condense and Speed-No- Load information including units, start/end times and start-ups required) with the service providers using the DDMS tool and notes within the CROW Log and whether differences are investigated and adjustments made prior to sending data to Settlements. Inspected a sample of generator source and quantity of Reactive Support and Voltage Control service provided in the DDMS tool to determine whether evidence of confirmation with the ancillary service provider was retained and that the differences, if any, were investigated and adjustment made prior to sending data to Settlements.	No deviations noted.
5.09	Settlement staff verifies speed no load offer rates submitted by the Market Participant, and then approves the results for import into the CRS.	Inquired of Settlement personnel to determine whether they verify that Speed No Load offer rates are submitted by the Market Participant, and approved by settlement staff for import into the CRS. Inspected a Speed No Load offer to determine whether it was approved by settlement staff prior to import into the CRS.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.10	IESO formally approves only those locations, if any that meet the generation station service rebate (GSSR) criteria outlined in the Market Rules. Only these locations are eligible to receive this rebate.	Inquired of Settlement personnel to determine whether the IESO formally approves only those locations, if any, that meet the Generation Station Service Rebate Criteria outlined in the Market Rules. Inspected a sample of the eligible Market Participants for GSSR to determine whether only eligible locations received the reimbursement.	No instances of GSSR delivery point approvals occurred during the period; therefore could not test operating effectiveness.
5.11	On a daily basis, the CRS GCG tool automatically assesses the applicability of each Market Participant GCG claim, and marks the GCG claim as either passed or rejected based on eligibility.	Inquired of Settlement personnel to determine whether on a daily basis, the GCG tool automatically assesses the applicability of each instance of Market Participant submission of costs, and marks the cost forms as either passed or rejected based on eligibility. Inspected a sample of the GCG tool's automatic assessment of applicability of Market Participants' submission of costs to determine whether the GCG tool marks the cost forms as either passed or rejected based on eligibility.	No deviations noted.
5.12	On a daily basis, settlement staff runs a GCG eligibility EUC tool to assess applicability of each instance of Market Participant GCG claim, for eligibility tests excluded from the CRS GCG automatic tool (5.11). GCG claims that pass in both the automated and EUC tools move on to the month-end calculation process.	Inquired of Settlement personnel to determine whether on a daily basis, settlement staff run a GCG eligibility EUC tool to assess applicability of each instance of Market Participant submission of costs, for applicability tests excluded from the automatic tool, and whether cost forms that are accepted by both the automated and EUC applicability assessments are used in the month-end calculation process. Inspected a sample of the GCG eligibility EUC tool’s evaluation reports to determine whether the GCG eligibility EUC tool is used to assess applicability of each instance of Market Participant submission of costs, for applicability tests excluded from the automatic tool, and whether cost forms that are accepted by both the automated and EUC applicability assessments are used in to the month-end calculation process.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.13	Settlement staff investigates the GCG Investigation Summary Report (produced by EUC tool) and the results claims produced by the CRS GCG tool that identify the rejected GCG claims to determine which rejected events are valid, then signs off on the results of the investigation. CRS GCG settlement claim record is updated to pass or fail depending on the result of eligibility tests.	Inquired of Settlement personnel to determine whether Settlement staff investigate rejected GCG events to determine which rejected events are valid, then signs off on the results of the investigation for the GCG tool to be updated to accept GCG events that are determined to have passed the eligibility criteria. Inspected a sample of Settlement Support GCG Investigation Summary reports to determine whether that claims rejected are valid. Inspected a sample of Settlement Support GCG Investigation Summary forms to determine whether the form was signed-off as evidence of review, and whether the GCG tool is updated to accept GCG events that are determined to have passed the eligibility criteria.	No deviations noted.
5.14	On a daily basis, Ex-Post staff reviews the Interchange Control Record, NERC E Tag System and audio logs and compare it with the Interchange Scheduler to assess for completeness and accuracy of transaction activity.	Inquired with Ex-Post personnel to determine whether Ex-Post staff review the Interchange Control Record and compare it with the information in the Interchange Scheduler program for completeness and accuracy of transaction activity. Inspected a sample of Interchange Control Records to determine whether the record matches with the Interchange Scheduler for completeness and accuracy of transaction activity as reviewed by the Ex-Post staff.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.15	On a monthly basis, Ex-Post staff confirms the month's summary of SMO activity with the Market Participant. Differences are investigated and adjustments made prior to sending data to Settlements.	Inquired with Ex-Post personnel to determine whether on a monthly basis, Ex-Post staff confirm the month's summary of SMO activity with the Market Participant, and whether differences are investigated and adjustments are made prior to sending data to Settlements. Inspected a sample of Market Participant communications with the IESO to determine whether Ex-Post staff confirms the month's summary of SMO activity with the Market Participant, and whether differences are investigated and adjustments are made prior to sending data to Settlements.	No deviations noted.
5.16	Data is electronically screened against predefined criteria by the LMP and COWZ tools to identify prices outside the acceptable range.	Inquired of Market Assessment Unit personnel to determine whether settlement data is electronically screened against predefined criteria by the LMP and COWZ tools to identify prices outside the acceptable range. Re-performed a sample CMSC payment outside the acceptable range to determine whether the settlement data was electronically screened by the LMP and COWZ tools against predefined criteria.	No deviations noted.
5.17	Market Assessment Unit (MAU) staff review against Constrained Off Watch Zone (COWZ) and Local Market Power (LMP) criteria to determine ineligibility for CMSC.	Inquired of MAU personnel to determine whether MAU staff review the settlement data against COWZ and LMP criteria to determine ineligibility for CMSC. Inspected a sample of CMSC payments to determine whether a review is performed by MAU to determine ineligibility for CMSC.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.18	Prior to transmitting spreadsheets with summaries of Local Market Power (LMP) debits/credits to the Settlements department, the supervisor of the MAU, approves the amounts contained in the spreadsheets.	Inquired of MAU personnel to determine whether on a monthly basis, MAU staff prepares a LMP spreadsheet with a summary of LMP debits/credits and sends it electronically to Settlement, and that the Manager, MAU, approves it prior to sending to Settlements. Inspected a sample of LMP summaries to determine whether the spreadsheet was approved by the Manager, MAU prior to sending it to Settlements.	No deviations noted.
5.19	MAU sends detailed CMSC charges/payments information to Market Participants for their review in conjunction with any data associated with LMP debits/credits. Inquiries, if any, are followed up and clarified by MAU staff.	Inquired of MAU personnel to determine whether MAU sends CMSC charges / payments information to Market Participants for their review in conjunction with any data associated with LMP debits / credits. Inspected a sample of CMSC charges/payments to determine whether charges/ payment information were sent to the Market Participant for review in conjunction with any data associated with LMP debits/credits.	No deviations noted.
5.20	Market Participant submits a NOD related to an administrative pricing event. Settlement staff checks for eligibility to be compensated for an administrative pricing event (reversal of negative CMSC and/or additional compensation for energy).	Inquired of Settlement personnel to determine whether Settlement staff confirm that the expected adjustment for the Administrative Pricing Event exceeds materiality thresholds. Inspected a sample of Administrative Pricing events that exceeded materiality thresholds to determine whether they were confirmed by the Settlement staff.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.21	For eligible claims, Settlement staff obtains confirmation from MACD that the Market Participant was compliant with dispatch instructions during the administrative pricing event.	Inquired of Settlement personnel to determine whether Settlement personnel confirm with MACD that the Market Participant was compliant with dispatch instructions during the Administrative Pricing Event. Inspected a sample of Administrative Pricing Events to determine whether Settlement personnel confirm with MACD that the Market Participant was compliant with dispatch instructions.	No deviations noted.
5.22	Settlement staff obtains confirmation from Ex-Post that an administrative pricing event took place during the period in question and provides the interval(s) used as the source to copy forward/back market schedules and prices to the affected dispatch intervals.	Inquired of Settlement personnel to determine whether Ex-Post confirms that an Administrative Pricing Events took place during the period in question and provides the interval(s) used as the source to copy forward/back market schedules and prices to the affected dispatch intervals. Inspected a sample of Ex-Post confirmations for Administrative Pricing Events to determine whether Ex-Post confirmed that an Administrative Pricing Event took place during the period in question and provided the interval(s) used as the source to copy forward/back market schedules and prices to the affected dispatch intervals.	No deviations noted.
5.23	On a daily and monthly basis, the Ex-Post staff confirms the Market Participant source, type and the quantity of manually procured operating reserve (OR) using notes in the CROW Log. Differences are investigated and adjustments made prior to sending data to Settlements.	Inquired of Ex-Post staff to determine whether Ex-Post staff review the Market Participant source, type and the quantity of manually procured operating reserve (OR) using notes from the Control Room Operations Window, and whether differences found are investigated and adjustments are made prior to sending data to Settlements. Inspected a sample of daily and monthly manually procured operating reserves to determine whether Ex-Post staff confirms the source, type and quantity, and whether differences found are investigated and adjustments are made prior to sending data to Settlements.	No instances of manually procured operating reserve occurred during the period; therefore could not test operating effectiveness.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
5.24	On a daily and monthly basis, the Ex-Post staff confirms the source and the quantity of emergency purchases/sales using notes in the CROW Log. Differences are investigated and adjustments made prior to sending data to Finance.	Inquired of Ex-Post staff to determine whether Ex-Post staff review the source and the quantity of emergency purchases/sales using notes from the Control Room Operations Window, and whether differences found are investigated and adjustments are made prior to sending data to Finance. Inspected a sample of an emergency purchase/sale to determine whether Ex-Post staff confirms the source and quantity of the purchase on a daily/monthly basis, and whether differences found are investigated and adjustments are made prior to sending data to Finance.	No instances of emergency purchases or sales occurred during the period; therefore could not test operating effectiveness.

Control Objective 6: Calculation and Allocation of Settlements Amounts (other than post-final calculations)

Controls provide reasonable assurance that settlement payments and charges are calculated and allocated completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.01	Settlement calculations and associated end user computing (EUC) tools are periodically assessed based on risk considering the inherent likelihood and impact of error, consistent with corporate policies and procedures.	Inquired of Settlement personnel to determine whether Settlement calculations and associated EUC tools are periodically assessed based on risk considering the inherent likelihood and impact of error, consistent with corporate policies and procedures. Inspected a sample Settlement - EUC Tools Risk and Control Assessment to determine whether EUC tools were periodically assessed based on risk and impact of error, consistent with corporate policies and procedures.	No deviations noted.
6.02	Access to end user computing tools (including Check Tool) is restricted to personnel based on their role and job function.	Inquired of Settlement personnel to determine whether access to EUC tools including Check Tool is restricted to personnel based on their role and job function. Inspected a sample of EUC tools and Check Tools to determine whether access is restricted to personnel based on their role and job function.	No deviations noted.
6.03	Backup copy of the current version of end user computing tool files is maintained in a secure location to ensure availability of the copy in case of loss or damage of the tool files.	Inquired of IT management to determine whether a backup copy of critical EUC tools is maintained in a secured location. Inspected a sample of EUC tools to determine whether a backup copy of the current version is maintained in a secure location.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.04	Previous version of the end user computing tool files and the tool's output and input files that are no longer being updated or modified are archived using IESO's archiving process.	Inquired of Settlement management to determine whether the previous version of the EUC tool files and the tool's output and input files that are no longer being updated or modified are archived using the IESO's archiving process. Inspected a sample of EUC tools to determine whether previous version of the end user computing tool files and the tool's output and input files that are no longer being updated or modified were archived using IESO's archiving process.	No deviations noted.
6.05	The tool file name includes the tool version number to identify the tool version being used, and the tool version number is incremented after each change to the logic of the EUC tool.	Inquired of Settlement personnel to determine whether the tool file name includes the tool version number to identify the tool version being used, and the tool version number is incremented after each change to the logic of the EUC tool. Inspected a sample of EUC tools to determine whether the tool file name includes the tool version number and that the version number was incremented after each change to the tool.	No deviations noted.
6.06	For medium and high risk tools, access to the reference copy of the latest approved version of the end user computing tools is restricted to staff based on role and job function and/or locking sensitive cells that are important for data processing. Write access to reference copy of the tool is restricted to change implementers.	Inquired of Settlement personnel to determine whether access to the reference copy of the latest approved version of the EUC tools is restricted to staff based on role and job function and/or locking sensitive cells that are important for data processing. Write access to reference copy of the tool is restricted to change implementers. Inspected a sample of EUC tools to determine whether access is restricted to personnel based on their role and job function and/or locking of sensitive cells that are important for data processing and that write access to reference copy of the tool was restricted to change implementers.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.07	For medium and high risk tools, check tools have been developed to provide independent verification that the results of the end user computing tool are reasonable.	Inquired of Settlement personnel to determine whether check tools have been developed to provide independent verification that the results of the EUC tool are reasonable. Inspected a sample charge to determine whether a check tool was used to provide independent verification of the results as computed by the high and medium risk EUC tool was performed.	No deviations noted.
6.08	For medium and high risk tools, changes to end user computing tools are documented by staff, authorized by senior staff other than requestor and developer, test results are accepted by senior staff, and implemented by senior staff into production.	Inquired of Settlement management to determine whether, for medium and high risk tools, changes to EUC tools are documented by staff, authorized by senior staff other than requestor and developer, test results are accepted by senior staff, and implemented by senior staff into production. Inspected a sample of medium and high risk EUC tool changes to determine whether the changes were documented by staff, authorized by senior staff other than requestor and developer, test results were accepted by senior staff, and implemented by senior staff into production.	No deviations noted.
6.09	Business process or system owners authorize the granting of new or transferred logical access privileges to the end user computing tools and logical access privileges are revoked on a timely basis for staff departures.	Inquired of Settlement management to determine whether business process owners or system owners authorize the granting of new or transferred logical access privileges to the EUC tools and logical access privileges are revoked on a timely basis for staff departures. Inspected a sample of EUC tool access changes to determine whether access grants were authorized and that logical access privileges were revoked on a timely basis for staff departures.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.10	For medium and high risk tools, the Market Settlements Manager reviews access for appropriateness for the end user computing tools four times annually. Identified exceptions are resolved on a timely basis.	Inquired of Settlement management to determine whether access to medium and high risk EUC tools are reviewed for appropriateness periodically and approved by business process owners. Inspected a sample of quarterly medium and high risk EUC tool user access reviews to determine whether the Manager, Market Settlement reviewed the EUC tools for appropriateness and exceptions were resolved on a timely basis.	No deviations noted.
6.11	The Business Process owners review user access for appropriateness for low risk end user computing tools on an annual basis. Identified exceptions are resolved on a timely basis.	Inquired of the business process manager to determine whether low risk EUC tools are reviewed for appropriateness on an annual basis. Inspected the annual low risk EUC tool user access review to determine whether the Business Process owners reviewed the access for appropriateness and exceptions, if any, were resolved on a timely basis.	No deviations noted.
6.12	For low risk EUC tools, settlement quantities prepared by Settlement staff are approved by senior Settlement staff.	Inquired of Settlements personnel to determine whether settlement quantities are prepared and approved for: SMO export transmission tariff, OR claw back, Bill 100 settlement of directly connected consumers at RPP rates, adjustments to reactive condense payments for negative HOEP, adjustment to reactive condense payments to account for daily uplift, Trans Alta Incremental Loss payments, settlement of forecasting services costs and distribution, negative price exports, CMSC clawback for COWZ, hour ending one PCG reversal, and transmission service charges for embedded generation settlements. Re-performed a sample calculation of each of the noted settlement quantities to determine whether they have been prepared accurately and approved timely.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.13	For medium and high risk end user computing tools, settlement quantities are prepared by creator, verified by the checker, and approved by senior Settlement staff.	Inquired of Settlement personnel to determine whether for medium and high risk end user computing tools, settlement quantities are prepared, verified and approved for: regulation, OPG Rebate, SMO CMSC clawback, IOG offset, IOG adjustment for MR323, Administrative Pricing NoDs, Bill 100 embedded generation & RPP settlements, TTDC offline Generation Station Service Rebate, Renewables connection cost recovery, reversal of constrained off CMSC payments to dispatchable loads for self induced ramping Regulation Service settlement for OPG and GLP, Regulated Hydroelectric Generation Adjustment, and CRS offline extraction/aggregation. Re-performed a sample calculation for each Manual Line Item (MLI) file to determine whether the amounts computed by the IESO's EUC tool is accurate.	No deviations noted.
6.14	For settlement quantities submitted manually to CRS that do not require end user computing tools, settlement quantities are prepared and approved by senior Settlement staff.	Inquired of Settlement personnel to determine whether for settlement quantities submitted manually to CRS that do not require EUC tools, settlement quantities are prepared and approved for: black start, SGOL and GCG allocation to load (i.e. the 'per units'), components of the global adjustment (i.e. OPA contracts and OEFC NUG adjustments) , Ontario Clean Energy Benefit and outage compensation amounts (claim validated by Market Forecasts and Integration). Re-performed a sample calculation submitted manually to CRS that did not require EUC tools to determine whether charges are calculated accurately.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.15	Settlement staff enters the data from the manual line items into CRS, then checks and signs off that the data was entered correctly.	Inquired of Settlement personnel to determine whether Settlement staff enter the data from the manual line items form into CRS, then checked and signed off that the data was entered correctly. Inspected a sample of manual line items to determine whether they contained appropriate signoffs from Settlement staff to signify the data was entered correctly.	No deviations noted.
6.16	Settlement staff enters input data for Speed no load offers to support automated charges into CRS, then check and sign off that the data was entered correctly.	Inquired of Settlement personnel to determine whether Settlement staff enter input data for Speed no load offers to support automated charges into CRS, then checks and signs off that the data was entered correctly. Inspected a sample of manual line items to determine whether the data for Speed no load offers was entered correctly into CRS, and that settlement staff's review was performed as evidenced by a signoff.	No deviations noted.
6.17	The CRS calculates variable charge types based on the appropriate market and system operational data.	Inquired of Settlement personnel to determine whether CRS calculates variable charge types based on the appropriate market and system operational data. Re-performed a sample of CRS variable charge types to determine whether CRS automatically calculated the variable charge types accurately.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
6.18	Settlement staff receives requests to change rates or constants (e.g. DRC exemptions or reductions, changes to HST rates, changes to tariff rates such as the IESO fee) or, time triggers the need to prepare the holiday schedule for the upcoming year. Changes are approved by the manager, or delegate (implementing DRC changes and tariff changes) or senior Settlement staff (holiday schedules). Settlement staff sign-off that the changes have been input successfully, and senior Settlement staff sign-off that they have verified the change.	Inquired of Settlement personnel to determine whether senior Settlement staff approves changes to CRS rates, constants or the holiday schedule before entry into CRS and whether Settlement staff update CRS with the fixed charge changes based on regulatory rulings. Inspected a sample of charge changes into CRS to determine whether the changes were accurate and approved by senior Settlement staff.	No deviations noted.
6.19	CRS calculates the fixed-charge types based on regulatory and legislative requirements.	Inquired of Settlement personnel to determine whether CRS calculates the fixed-charge type based on regulatory and legislative requirements. Re-performed sample CRS fixed-charge type calculations to determine whether CRS calculated the charges accurately based on regulatory and legislative requirements.	No deviations noted.
6.20	The Meter Data Management system transfers data to the Transmission Tariff Demand Calculator (TTDC) system. TTDC calculates peak demand then transfers transmission tariff data to CRS for subsequent settlement processing.	Inquired of Settlement personnel to determine whether MV-Star transfers data to the Transmission Tariff Demand Calculator system for calculation of peak demand. Re-performed a sample TTDC calculation to determine whether the TTDC system calculates peak demand accurately. Inspected a sample TTDC transaction to determine whether the TTDC transaction was transferred to CRS for subsequent settlement processing accurately.	No deviations noted.

Control Objective 7: Post-Final Calculations

Controls provide reasonable assurance that post-final calculations are calculated and allocated completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.01	Settlement management and senior staff review the settlement issue against certain criteria (e.g., Market Rule obligation, Legislation, Procedures, materiality) and assess whether a post-final calculation should be made. The decision to proceed with a post-final calculation is documented and signed by the Manager, Market Settlement.	Inquired of Settlement personnel to determine whether Settlement Management and Senior staff review the settlement issue against certain criteria (e.g., Market Rule obligation, legislation, procedures, materiality) to assess whether a post-final calculation should be made and that the decision to proceed is documented and signed by the Manager, Market Settlements. Inspected a sample of post-final calculations to determine whether the decision to proceed with a post-final calculation is documented and signed by the Manager, Market Settlements.	No deviations noted.
7.02	Settlement staff assess that the corrected data submitted by the MMP/MSP for a metering data issue is reasonable. Reasonability test includes: • Data has passed validation • Estimated data compare favourably with data before and after the validation period. In addition, Senior Settlement staff sign off that the reasonability assessment has concluded favourably.	Inquired of Settlement personnel to determine whether Settlement staff perform an assessment of data to check that the corrected data submitted by the MMP/MSP for a metering data issue is reasonable, and whether Senior Settlement staff sign off that the assessment was concluded favourably Inspected a sample of corrected data submitted by MMP/MSP to determine whether Settlement staff documented and signed off a reasonability assessment. Inspected to determine whether Senior staff signed off that the reasonability assessment was concluded favourably	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.03	Settlement staff propose a method to estimate a correction to meter data (when the MSP corrected data is not reasonable, or when there is a meter reconciliation error or a meter data management error). The estimation methodology is approved by the Manager, Meter Data Management.	Inquired of Settlement personnel to determine whether Settlement staff propose a method to estimate a correction to meter data and that the proposed estimation methodology is approved by the Manager, Meter Data Management. Inspected a sample of corrected meter data to determine whether the proposed estimation methodology was documented by Settlement staff and approved by the Manager, Meter Data Management.	No deviations noted.
7.04	Settlement staff review the revised delivery point data produced by the MV-Star system (offline or production) and assesses if the data is reasonable given: • changes to the meter data in the MV-90 system (offline or production); and/or • changes made to correct the totalization table in the MV-Star system (offline or production). Discrepancies, if any, are investigated and resolved. Senior Settlement staff sign off that the reasonability assessment has concluded favourably.	Inquired of Settlement personnel to determine whether Settlement staff review the revised delivery point data produced by the MV-Star system (offline or production) and assesses if the data is reasonable based on changes to meter data and/or changes made to correct the totalization table, whether differences are investigated and adjustments made, and whether Senior Settlement staff sign-off that the reasonability assessment was concluded favourably. Inspected a sample of post final calculations to determine whether Settlement staff review the revised delivery point data produced by the MV-Star system (offline or production) and assess if the data is reasonable based on changes to meter data and/or changes made to correct the totalization table, whether any discrepancies were investigated and resolved, and Senior Settlement staff provided sign-off.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.05	Settlement staff verifies the results of the TTDC end user computing tool by executing a ‘check tool’ version of the tool and comparing the results.	Inquired of Settlement personnel to determine whether Settlement staff verify the results of the TTDC end user computing tool by executing a "check tool" version of the tool and comparing the results. Inspected a sample TTDC calculation to determine whether a comparison of the results via the check tool was performed.	No deviations noted.
7.06	Settlement staff verifies that the calculated energy adjustment match the estimated energy adjustment within a small error band. Material discrepancies, if any, are identified and resolved. Senior Settlement staff sign off that the energy adjustment matches the estimate.	Inquired of Settlement personnel to determine whether Settlement staff verify that the energy adjustment calculated by the CRS offline system matches the estimated energy adjustment within a small error band, whether material discrepancies, if any are investigated and resolved, and whether Senior Settlement staff sign-off that the energy adjustment matches the estimate. Inspected a sample energy adjustment to ascertain whether calculated energy adjustment matched the estimated energy adjustment, whether material discrepancies were identified and resolved, and whether Senior Settlement staff signed off that the energy adjustment matched the estimate.	No deviations noted.

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	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.07	Settlement staff assess that the results of the offline Global Adjustment distribution EUC tool are reasonable. Assessment of reasonability is based upon expectations formed during earlier stages of the process (issue assessment, meter data processing, totalization table changes, delivery point data review) and includes the following: • check Global Adjustment AQEW allocation amounts are correct for the applicable distribution period • check that the sum of the GA distributions equals the total GA adjustments. Discrepancies, if any, are investigated and resolved. Senior Settlement staff sign off that the reasonability assessment has concluded favourably.	Inquired of Settlement personnel to determine whether Settlement staff assess that the results of the offline Global Adjustment distribution EUC tool are reasonable and whether assessment of reasonability is based upon expectations formed during earlier stages of the process. Inquired to determine whether discrepancies if any are investigated and resolved and whether Senior staff sign off that the reasonability assessment has concluded favorably. Inspected a sample adjustment of the Global Adjustment calculated by the GA EUC tool to ascertain whether results of the offline Global Adjustment calculation/distribution EUC tool(s) are reasonable, whether any discrepancies were investigated and resolved, and whether Senior staff sign off that the results are reasonable	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.08	Settlement staff assess that the MLIs prepared are reasonable. Assessment of reasonability is based upon expectations formed during earlier stages of the process (issue assessment, processing meter data, process totalization table changes, review of delivery point data) and includes one or more of the following: • Review of summary reports prepared by the EUC tool that demonstrate that adjustments are balanced • Comparison of Total Energy Adjustments (CT100, CT101) with estimated results • Check if CT753 ($/MWh) is consistent with the total measurement adjustment • Check if the adjustments have the expected sign (e.g. increased AQEW should have negative energy adjustments) • Review rates used related to uplifts, fixed rate charges, and global adjustment Discrepancies, if any, are investigated and resolved.	Inquired of Settlement personnel to determine whether Settlement staff verifies that the MLIs prepared are reasonable based on their assessment, and whether discrepancies, if any, are investigated and resolved. Inspected a sample MLI to ascertain whether it was assessed by Settlement staff as reasonable based on stated criteria, and whether any discrepancies were investigated and resolved.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.09	Settlement staff confirm that GCG data for each GCG claim to be calculated by the GCG offline tool has been correctly loaded into the tool (CRS offline).	Inquired of Settlement personnel to determine whether Settlement staff confirm that GCG data for each GCG claim to be calculated by the GCG offline tool had been correctly loaded into the tool. Inspected a sample GCG claim to determine whether Settlement staff confirm that each GCG claim to be calculated by the GCG offline tool had been correctly loaded into the tool.	No instances of GCG offline calculation occurred during the period; therefore, could not test operating effectiveness.
7.10	Settlement staff manually investigate the CRS eligibility assessment all claims that were rejected and validate 10% of claims that were determined to be valid based on eligibility rules (CRS offline).	Inquired of Settlement personnel to determine whether Settlement staff manually investigate all claims that were rejected and validate 10% of claims that were determined to be valid based on eligibility rules. Inspected a sample investigation of claims to determine whether Settlement staff manually investigates all claims that were rejected and validate 10% of claims that were determined to be valid based on eligibility rules.	No instances of GCG offline calculation occurred during the period; therefore, could not test operating effectiveness.
7.11	Settlement staff executes a check tool for a sample of 10% of the GCG offline events, to determine that the offline tool is calculating claim amounts correctly. Differences greater than $100 are investigated and resolved.	Inquired of Settlement personnel to determine whether Settlement staff execute a check tool for a sample of 10% of GCG offline events to determine that the tool is calculating claim amounts correctly, and whether differences greater than $100 are investigated and resolved. Inspected a sample of GCG offline events to determine whether for 10% of events, Settlement staff executed a check tool to determine whether the claim amounts were calculated correctly, or if differences greater than $100 was present, that they were investigated and resolved.	No instances of GCG offline calculation occurred during the period; therefore, could not test operating effectiveness.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
7.12	Settlement staff confirm that PCG input data to be used in the CRS offline calculation has been correctly loaded into the offline tool.	Inquired of Settlement personnel to determine whether Settlement staff confirm that PCG input data to be used in the CRS offline calculation has been correctly loaded into the offline tool. Inspected a sample CRS offline calculation to determine whether Settlement staff confirmed that PCG input data to be used in the calculated was correctly loaded into the tool.	No instances of PCG offline calculation occurred during the period; therefore, could not test operating effectiveness.
7.13	Settlement staff manually assess the reasonability of the PCG results of the CRS offline calculation based on a sample of the calculation results, in order to ensure that the offline tool is calculating claim amounts correctly.	Inquired of Settlement personnel to determine whether Settlement staff manually assess the reasonability of the PCG results of the CRS offline calculation based on a sample of the calculation results, in order to ensure that the offline tool is calculating claim amounts correctly. Inspected a sample of CRS offline calculations to determine whether Settlement staff manually assess the reasonability of PCG results in order to ensure that the tool is calculating claim amounts correctly.	No instances of PCG offline calculation occurred during the period; therefore, could not test operating effectiveness.

Control Objective 8: Preliminary and Final Settlement Statements

Controls provide reasonable assurance that preliminary and final settlement statements provided to Market Participants are complete, accurate and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
8.01	The CRS creates preliminary and final settlement statements in accordance with the settlement schedule and payment calendar.	Inquired of Settlement personnel to determine whether CRS creates preliminary and final settlements in accordance with the settlement schedule and payment calendar. Inspected a sample trade date to determine whether the preliminary and final settlement statements were created by CRS in accordance with the settlement schedule and payment calendar.	No deviations noted.
8.02	Settlement staff review CRS error logs daily. Errors are investigated and resolved.	Inquired of Settlement staff to determine whether Settlement staff review CRS error logs on a daily basis and errors are investigated and resolved. Inspected a sample error log to determine whether Settlement staff performed a review and whether errors, if any, were investigated and resolved.	No deviations noted.
8.03	Settlement staff review the neutrality reports to ascertain that the market charges have a net balance of zero (within a small tolerance associated with calculation rounding) and accounting for known transactions to the IESO account or other specified accounts. Discrepancies are investigated and resolved.	Inquired of Settlement personnel to determine whether Settlement staff review the neutrality reports to ascertain that market charges have a net balance of zero (within a small tolerance associated with calculation rounding), and accounting for known transactions to the IESO account, or other specific accounts. Inspected a sample neutrality report to determine whether market charges have a net balance of zero, within allowed tolerances, and Settlement staff review the report for discrepancies and investigate any issues.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
8.04	Settlement staff reconcile the number of preliminary statements to the number of final settlement statements.	Inquired of Settlement personnel to determine whether Settlement staff reconcile the number of final statements produced for a trade day, to the number of preliminary statements that were that were issued for the same trade day in the past. Inspected a sample of reconciliations to determine whether the number of preliminary and final statements issued were reconciled.	No deviations noted.
8.05	Settlement staff signs off a standardized daily checklist for the production of settlement statements.	Inquire of Settlement personnel to determine whether the Settlement staff sign-off on daily checklists. Inspect a sample a daily checklists and ascertain that the Settlement staff provide their sign-off as evidence of review.	No deviations noted.

Control Objective 9: Invoices and Invoice Adjustments

Controls provide reasonable assurance that invoices and invoice adjustments that are provided to Market Participants are complete, accurate and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
9.01	The Market Invoice Analyst reconciles the Unbilled Settlements BITS Query to determine Settlement data in the CRS agrees with settlement data in Lawson.	Inquired of Finance personnel to determine whether the Market Invoice Analyst reconciles the Unbilled Settlements Report with BITS Query to determine whether settlement data in CRS agrees with settlement data in Lawson. Inspected a sample of Unbilled Settlements Reports to determine whether the report was reconciled to the settlement data in Lawson by the Market Invoice Analyst.	No deviations noted.
9.02	The Market Invoice Analyst reconciles the Unbilled Settlements BITS Query output with output from Lawson to determine whether transactions are transferred completely, accurately and on a timely basis from Lawson to the Managed File Transfer (MFT).	Inquired of Finance personnel to determine whether the Market Invoice Analyst reconciles file processing reports to determine whether transactions generated by Lawson are transferred completely, accurately and timely to MFT Inspected a sample MFT report to determine whether the Market Invoice Analyst reconciles the transactions generated by the Lawson are transferred completely, accurately and on a timely basis to the MFT.	No deviations noted.
9.03	The Market Invoice Analyst reconciles and reviews a Lawson system report comparing to transaction log prior to transferring Credit Invoices to A/P to determine that the transfer will be complete, accurate and timely.	Inquired of Finance personnel to determine whether Market Invoice Analyst reconciles and reviews a Lawson system report comparing to transaction log prior to transferring Credit Invoices to A/P to determine that the transfer will be complete, accurate and timely. Inspected a sample AR to AP Interface report and expense report to determine whether the transactions generated by the Lawson AR module are transferred completely, accurately and timely to the Lawson AP module.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
9.04	The Manager, Finance and Accounting reviews and approves a reconciliation of the transaction log before and after the allocation of pre-payments to invoices.	Inquired of Finance personnel to determine whether the Manager, Finance and Accounting reviews and approves a reconciliation of the transaction log before and after the allocation of pre-payments to invoices. Inspected a sample transaction log before and after allocation of pre-payments to invoices to determine whether the review and approval of the reconciliation was performed by the Manager, Finance and Accounting.	No deviations noted.
9.05	The Manager, Finance and Accounting reviews and approves invoice adjustments before they are entered into Lawson.	Inquired of Finance personnel to determine whether the Manager, Finance and Accounting reviews and approves invoice adjustments before they are entered into Lawson. Inspected a sample of invoice adjustment in Lawson to determine whether the invoice adjustment was reviewed and approved by the Manager, Finance and Accounting before it is entered into Lawson.	No deviations noted.
9.06	The Manager, Finance and Accounting reviews and approves manual invoices and supporting documentation.	Inquired of Finance personnel to determine whether the Manager, Finance and Accounting reviews and approves manual invoices and supporting documentation. Inspected a sample of manual invoices to determine whether the invoice was reviewed and approved by the Manager, Finance and Accounting.	No deviations noted.

Control Objective 11: Cash Receipts

Controls provide reasonable assurance that cash receipts for settlement charges due to the IESO are processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
11.01	The Treasury System automatically downloads Bank receipts from the IESO's bank daily and matches receipts to forecasted receipts.	Inquired of Treasury personnel to determine whether the Treasury System automatically downloads Bank receipts from the IESO's bank daily and matches receipts to forecasted receipts. Re-performed a sample automated matching of Bank receipts to forecasted receipts by the Treasury System to determine whether the Treasury System correctly matched receipts.	No deviations noted.
11.02	The Treasury Associate reviews all unmatched receipts and resolves any unmatched receipts based on the Treasury System's daily "Unmatched Items" report. If required, the Treasury Associate, the Market Invoice Analyst or Treasury Analyst follows up with Market Participants and/or the Bank to determine the reason for unmatched receipts or other differences.	Inquired of Treasury personnel to determine whether the Treasury Associate reviews all unmatched receipts and resolves any unmatched receipts based on the Treasury System's daily "Unmatched Items" report, and whether the Treasury Associate, the Market Invoice Analyst or Treasury Analyst follows up with Market Participants and/or the Bank to determine the reason for unmatched receipts or other differences. Inspected a sample of unmatched receipts in the Treasury Management system to determine whether the Treasury Associate, the Market Invoice Analyst or Treasury Analyst resolved irregular unmatched receipts, if any, and followed up with the Market Participant and/or the Bank to determine the reason for unmatched receipts or other differences.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
11.03	Finance staff monitors the timeliness of cash receipts in accordance with the Market Rules. Known or expected receipts (as when due) are inputted/loaded as forecasts into the Treasury System by the Treasury Associate.	Inquired of Finance personnel to determine whether Finance staff monitors the timeliness of cash receipts in accordance with the Market Rules. Inspected a sample of monthly past due invoice reports for outstanding invoices to determine whether Finance staff review the report for timeliness of cash receipts in accordance with the Market Rules.	No deviations noted.
11.04	For all other receipts such as prepayments, the Market Invoice Analyst reconciles the Unapplied Receipts Report to the Treasury Management system AR Export Report to verify that cash receipts are completely and accurately transferred from Treasury.	Inquired of Finance personnel to determine whether all other receipts such as prepayments, the Market Invoice Analyst reconciles the Unapplied AR Payments Report to the Treasury Management system AR Export Report to verify that cash receipts are completely and accurately transferred from Treasury. Inspected a sample of reconciliations between Lawson AR and the Treasury Management system AR Export Report to determine whether the Market Invoice Analyst reconciled the report and verified that cash receipts were completely and accurately transferred.	No deviations noted.
11.05	The Treasury Analyst performs bank reconciliations monthly to review the automated download of data. The Supervisor, Corporate Finance reviews and approves the reconciliation.	Inquired of Treasury personnel to determine whether the Treasury Analyst performs bank reconciliations monthly to review the automated download of data and whether they are reviewed and approved by the Supervisor, Corporate Finance. Inspected a sample of monthly bank reconciliations to determine whether they were performed by the Treasury Analyst and reviewed and approved by the Supervisor, Corporate Finance.	No deviations noted.

Control Objective 13: Cash Disbursements

Controls provide reasonable assurance that cash disbursements due to Market Participants are processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
12.01	The Treasury Associate and Market Invoice Analyst jointly verify each payment prior to the Market Invoice Analyst sending out the EFT file for payment release.	Inquired of Treasury personnel to determine whether the Treasury Associate and Market Invoice Analyst jointly verify each payment prior to the Market Invoice Analyst sending out the EFT file for payment release. Inspected a sample of EFT payment files to determine whether the Treasury Analyst and Market Invoice Analyst jointly verified EFT payment files to the Lawson Payment Register for completeness and accuracy.	No deviations noted.
12.02	The Manager, Finance and Accounting compares and reviews the payment register reports against the transaction logs of actual payments to the bank for completeness and accuracy.	Inquired with the accounting personnel to determine whether the Manager, Finance and Accounting compares and reviews the payment register reports against the transaction logs of actual payments to the bank for completeness and accuracy. Inspected a sample of payment register reports to determine whether the Treasury Analyst and Market Invoice Analyst compared and reviewed the payment register reports against the transaction logs of actual payments to the bank for completeness and accuracy.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
12.03	The Treasury Analyst performs bank reconciliations monthly to review the automated download of data. The Manager, Finance and Accounting reviews and approves the reconciliation.	Inquired of Treasury personnel to determine whether the Treasury Analyst performs a reconciliation of the treasury system output with the bank statements, and whether the Supervisor, Corporate Finance reviews and approves the reconciliation. Inspected a sample of monthly treasury system output reports to determine whether the Treasury Analyst reconciled the report to the bank statement. Inspected a sample of monthly bank balance reports to determine whether the Invoice Analyst reconciled the report with the Market GL balances and the account obligations. Inspected a sample of monthly reconciliations to determine whether it was approved by the Manager, Finance and Accounting.	No deviations noted.
12.04	The Treasury system is set up in accordance with the IESO's Approved Financial Instruments Listing.	Inquired of Treasury personnel to determine whether the Treasury System is set up in accordance with the IESO's Approved Financial Instruments Listing. Inspected the Treasury System settings to determine whether the Treasury System is set up in accordance with the IESO's Approved Financial Instruments Listing.	No deviations noted.

Control Objective 13: Disagreements

Controls provide reasonable assurance that disagreements are processed completely, accurately and timely in accordance with the Market Rules.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
13.01	The notice of disagreement (NoD) tool time and date stamps a notice of disagreement upon submission by a Market Participant.	Inquired of Settlement personnel to determine whether the NoD system date stamps a notice of disagreement upon submission by a Market Participant. Inspected a sample of NoDs to determine whether the NoD system date stamps the notice of disagreement automatically.	No deviations noted.
13.02	Settlement staff review the validity of the NOD claims submitted by the Market Participant to determine whether the information required to be submitted with the NOD was included. On-line input form has auto validation to ensure required fields are completed.	Inquired of Settlement personnel to determine whether the NoD system performed edit checks on notice of disagreement submissions by the Market Participants to determine whether the information required to be submitted with the NoD was included. Inspected a sample of NoDs submitted by Market Participants to determine whether the notice of disagreement submissions by the Market Participants contained the information required to be submitted.	No deviations noted.
13.03	Settlement staff confirm that NOD adjustment is required. Senior staff approving the MLI adjustment reviews and approves the analysis.	Inquired of Settlement personnel to determine whether Settlement staff confirms that NoD adjustments are entered into statement subsequent settlement statement for that Market Participant. Inspected a sample of NoD adjustments to determine whether they were reviewed before it was recorded. Inspected a sample of settlement statements to determine whether the information was recorded into CRS accurately to be included in a subsequent settlement statement for that Market Participant.	No deviations noted.
13.04	Senior Settlement staff review the analysis and approves on behalf of	Inquired of Settlement personnel to determine whether the Settlement staff review the analysis and approves on behalf	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
	the manager all NOD decisions. Senior Settlement staff review the analysis for completeness and approves with the manager all unique, unusual and significant disagreements processed.	of the manager all notices of disagreement decisions. In addition, inquired of settlement personnel to determine whether Settlement staff review with the manager all unique, unusual and significant disagreements processed. Inspected a sample of NoDs to determine whether they were reviewed and approved by the Settlement staff and whether unique, unusual and significant disagreements processed were reviewed with the manager.	

Control Objective 14: User Access

Controls provide reasonable assurance that access within applications to update or modify data is restricted to appropriate personnel.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
14.01	Only appropriate personnel have access within the MDMS application to update metering data.	Inquired of application process owner to determine whether only appropriate personnel have access within the MV-Star application to update metering data. Inspected the MV-Star user access list defined in the system to determine whether only appropriate personnel have access within the MV-Star application to update metering data.	No deviations noted.
14.02	Only appropriate personnel have access within the Meter Data Acquisition System (MDAS) application to update metering data.	Inquired of application process owner to determine whether only appropriate personnel have access within the MV-90 application to update metering data. Inspected the MV-90 user access list defined in the system to determine whether only appropriate personnel have access within the MV-90 application to update metering data.	No deviations noted.
14.03	Only appropriate personnel have access within the Meter Trouble Reporting application to update meter trouble reports.	Inquired of application process owner to determine whether only appropriate personnel have access within the Meter Trouble Reporting application to update meter trouble reports. Inspected the Meter Trouble Reporting user access list defined in the system to determine whether only appropriate personnel have access within the Meter Trouble Reporting application to update meter trouble reports.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
14.04	Only appropriate personnel have access within the Surveillance Data Repository (SDR) data warehouse to update market and operations data (prices, schedules).	Inquired of application process owner to determine whether only appropriate personnel have access within the Surveillance Data Repository data warehouse to update market and operations data (prices, schedules). Inspected the user access list defined in the system to determine whether only appropriate personnel have access within the Surveillance Data Repository data warehouse to update market and operations data (prices, schedules).	No deviations noted.
14.05	Only appropriate personnel have access within the Market Information Management (MIM) application to add or modify market data.	Inquired of application process owner to determine whether only appropriate personnel have access within the MIM application to add or modify market data. Inspected the user access list defined in the system to determine whether only appropriate personnel have access within the MIM application to add or modify market data.	No deviations noted.
14.06	Only appropriate personnel have access within the Transmission Rights Auction (TRA) application to update transmission rights data.	Inquired of application process owner to determine whether only appropriate personnel have access within the TRA application to update transmission rights data. Inspected the TRA user access list defined in the system to determine whether only appropriate personnel have access within the TRA application to update transmission rights data.	No deviations noted.
14.07	Only appropriate personnel have access within the CRS application to update settlement data.	Inquired of application process owner to determine whether only appropriate personnel have access within the CRS application to update settlement data. Inspected the CRS user access list defined in the system to determine whether only appropriate personnel have access within the CRS application to update settlement data.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
14.08	Only appropriate personnel have access within the Generation Cost Guarantee application to update settlement data.	Inquired of application process owner to determine whether only appropriate personnel have access within the Generation Cost Guarantee application to update settlement data. Inspected the Generation Cost Guarantee user access list defined in the system to determine whether only appropriate personnel have access within the Generation Cost Guarantee application to update settlement data.	No deviations noted.
14.09	Only appropriate personnel have access within the Lawson application to update settlement data.	Inquired of application process owner to determine whether only appropriate personnel have access within the Lawson application to update settlement data. Inspected the Lawson user access list defined in the system to determine whether only appropriate personnel have access within the Lawson application to update settlement data.	No deviations noted.
14.10	Only appropriate personnel have access within the Treasury Management system to review and manage banking transactions.	Inquired of application process owner to determine whether only appropriate personnel have access within the Treasury Management system to review and manage banking transactions. Inspected the Treasury Management user access list defined in the system to determine whether only appropriate personnel have access within the Treasury Management system to review and manage banking transactions.	No deviations noted.
14.11	Only appropriate personnel have access within the Notice of Disagreement system to update disagreement data.	Inquired of application process owner to determine whether only appropriate personnel have access within the NoD system to update disagreement data. Inspected the NoD user access list defined in the system to determine whether only appropriate personnel have access within the NoD system to update disagreement data.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
14.12	Only appropriate personnel have access within the CROW Log system to add or modify IESO-controlled grid and ancillary service log items.	Inquired of application process owner to determine whether only appropriate personnel have access within the CROW system to add or modify IESO-controlled grid and ancillary service log items. Inspected the CROW user access list defined in the system to determine whether only appropriate personnel have access within the CROW system to add or modify IESO-controlled grid and ancillary service log items.	No deviations noted.
14.13	Only appropriate personnel have access within the Customer Data Management System (CDMS) application to add or modify organizational data.	Inquired of application process owner to determine whether only appropriate personnel have access within the CDMS application to add or modify organizational data. Inspected the CDMS user access list defined in the system to determine whether only appropriate Finance personnel have access within the CDMS application to add or modify organizational data.	No deviations noted.
14.14	Only appropriate personnel have access within the Managed File Transfer (MFT) to retrieve reports related to physical and financial markets.	Inquired of application process owner to determine whether only appropriate personnel have access within MFT to retrieve reports related to physical and financial markets. Inspected the MFT user access lists in the system to determine whether only appropriate personnel have access within MFT to retrieve reports related to physical and financial markets.	No deviations noted.
14.15	Only appropriate personnel have access within the Dispatch Data Management System (DDMS) to add or modify interchange schedule, ancillary service data and generator constraints.	Inquired of application process owner to determine whether only appropriate personnel have access within the DDMS to retrieve invoice, settlement statements, and to set-up data files. Inspected the DDMS user access list in the system to determine whether only appropriate personnel have access within the DDMS to retrieve invoice, settlement statements, and to set-up data files.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
14.16	Only appropriate personnel have access within Settlements Portal community to add settlement data.	Inquired of application process owner to determine whether only appropriate personnel have access within the Settlements Portal community to add settlement data. Inspected the Settlements Portal user access list in the system to determine whether only appropriate personnel have access within the Settlements Portal community to add settlement data.	No deviations noted.
14.17	Logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or their delegates.	Inquired of application process owner to determine whether logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or delegates. Inspected a sample review to determine whether logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or delegates.	Deviation noted. For one (1) of eighteen (18) periodic logical access privilege reviews sampled, inappropriate employee access was not detected and removed as part of the review. Refer to Management Response below.
14.18	Only appropriate personnel have access within the Market Participant Prudential System (MPPS) that calculates Market Participants' financial risk to the market.	Inquired of application process owner to determine whether only appropriate personnel have access within the MPPS that calculates Market Participants’ financial risk to the market. Inspected the MPPS user access list in the system to determine whether only appropriate personnel have access within the MPPS.	No deviations noted.

Management Response (Control 14.17)

The auditor’s report identifies an instance where access was granted to an employee with a similar first name of the employee intended to be granted the access to specific application servers. The application servers are Linux-based systems, and for those specific systems it is possible, when provisioning users, to enter more than one user at a time based on a search of “firstname” in the account administration tool. Two employees, instead of one, were selected by the operator. By reviewing the home directories created on the servers, it was validated that the second employee, who was added in error, did not access the servers.

The IESO understands the importance of assigning the correct privileges to the employees that require those privileges, and that periodic reviews of access privileges are conducted with sufficient diligence such that appropriate access permissions are only granted to those employees who are authorized to have them.

Control Objective 15: Risk Management

Controls provide reasonable assurance that settlement process risks are identified, assessed, prioritized, mitigated and monitored in accordance with the IESO's Enterprise Risk Management policy.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
15.01	Potential risk events that would hinder the achievement of the Settlement Processing business objectives are identified and assessed by Settlements Staff four times per year.	Inquired of Risk Management personnel to determine whether potential risk events that would hinder the achievement of the Settlement Processing business objectives are identified and assessed four times per year. Inspected a sample of risk matrices for settlements processing to determine whether potential risk events that would hinder the achievement of the Settlement Processing business objectives are identified and assessed by Settlements staff.	No deviations noted.
15.02	Identified risks are prioritized by assessing the probability of occurrence and the significance of the impact of the risks on the achievement of the annual Settlements Processing objectives. The assessments are based on direction provided by the risk assessment and rating guidelines.	Inquired of Risk Management personnel to determine whether identified risks are prioritized by assessing the probability of occurrence and the significance of the impact of the risks on the achievement of the annual settlements processing objectives. Inspected a sample of quarterly heat maps for settlements processing to determine whether the identified risks are prioritized by assessing the probability of occurrence and the significance of the impact of the risks on the achievement of the annual Settlements Processing objectives.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
15.03	Risk mitigation activities are developed and implemented when residual risks are unacceptable, through the documentation of the action plans and their effectiveness.	Inquired of Risk Management personnel to determine whether risk mitigation activities are developed and implemented when residual risks are above management's tolerance, through the documentation of the action plans and their effectiveness. Inspected a sample of risk mitigation activities reports to determine whether the action plans have been developed and are tracked to determine their effectiveness.	No deviations noted.
15.04	Risk information is assessed annually and the results of the enterprise risk assessment and/or changes to risks are captured in risk spreadsheets. Key risks are reported to the Executive Management Team and the Audit Committee at least annually. Mitigation plans are reported quarterly to the Audit Committee.	Inquired of Risk Management personnel to determine whether risk information and results of the risk management process are reviewed and provided to Executive Leadership and the Board of Directors periodically. Inspected a sample of risk management reports to determine whether the risk information, results of the risk management process and mitigation plans have been provided to Executive Leadership and the Audit Committee.	No deviations noted.

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Control Objective 16: Change Management

Controls provide reasonable assurance that changes to critical production systems are documented, authorized, tested, approved, and properly implemented.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
16.01	Change and release management governing documents, including change and release management methodology which govern changes to critical production systems and their supporting environment exist and are documented.	Inquired of IT management to determine whether change and release management policies and methodology governing changes to critical production systems and their supporting environment exist and are documented, periodically reviewed, updated as necessary, and communicated to those individuals who are expected to comply with it. Inspected the change and release management policies and methodology documents to determine whether the policy and methodology documents were made available to staff and were periodically reviewed and updated where necessary.	No deviations noted.
16.02	There are defined roles and responsibilities for the authorization, development and implementation of changes within the change and release management process.	Inquired of IT management to determine whether there are defined roles and responsibilities for the authorization, development and implementation of changes within the change and release management process. Inspected the IT organization charts and the change and release management methodology to determine whether there are defined roles and responsibilities for the authorization, development and implementation of changes.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
16.03	Proposed changes are logged, documented, assessed for impact, and are authorized by the appropriate personnel.	Inquired of IT management to determine whether proposed changes are logged and documented, assessed for impact, and are authorized by the appropriate personnel. Inspected a sample of changes from the change management tool to determine whether proposed changes were logged, details of the changes were documented, assessed for impact, and the change included the appropriate authorization.	No deviations noted.
16.04	Test plans are developed, documented and executed for significant changes to critical production systems, including operating system and database which support the production application to determine that changes produce the expected outcome.	Inquired of IT management to determine whether test plans are developed, documented and executed for significant changes to critical production systems to determine that changes produce the expected outcome. Inspected a sample of changes from the change management tool to determine whether significant changes to critical production systems, as well as the operating system and database which support the production applications, had documented test plans and test results to determine that changes produce the expected outcome.	No deviations noted.
16.05	A committee with representation from user groups affected by system changes approves proposed non-emergency changes before they are implemented into the production environment.	Inquired of IT management to determine whether a committee with representation from user groups affected by system changes approves proposed non-emergency changes before they are implemented into the production environment. Inspected a sample of changes from the change management tool to determine whether proposed non-emergency changes were approved by a committee with representation from user groups before they were implemented into the production environment.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
16.06	The “after the fact” change process has been designed to follow the same process as normal changes except that documented approval is obtained in a timely manner subsequent to the promotion to production.	Inquired of IT management to determine whether the “after the fact” change process has been designed to follow the same process as normal changes except that documented approval is obtained in a timely manner subsequent to the promotion to production. Inspected a sample of “after the fact” changes from the change management tool to determine whether “after the fact” changes followed the documented change process and formal documented approval was obtained in a timely manner subsequent to the promotion to production.	No deviations noted.
16.07	After implementation, IT staff performs a review and approval of system modifications made during an “After the Fact” change.	Inquired of IT management to determine whether IT staff performs a post-implementation review of system modifications made during an emergency. Inspected a sample of “after the fact” changes from the change management tool to determine whether a post-implementation review was performed.	No deviations noted.
16.08	Critical production systems are regularly monitored for unauthorized changes where technical means to do so are practical.	Inquired of IT management to determine whether critical production systems are regularly monitored for unauthorized changes through change detection tools. Inspected a sample of changes from the change detection tool to determine whether critical production systems were monitored for unauthorized changes.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
16.09	For application changes, different individuals program the change, approve the change and move the change into production.	Inquired of IT management to determine whether there are defined roles and responsibilities for the development, approval and implementation of changes within the change and release management process. Inspected change and release management policies and methodology documents to determine whether there are defined roles and responsibilities for the development, approval and implementation of changes within the change and release management process. Inspected a sample of changes from the change management tool to determine whether different individuals develop, approve and implement application changes to production.	No deviations noted.

Control Objective 17: Logical and Physical Access

Controls provide reasonable assurance that logical access to critical production systems and data, and physical access to computer equipment is restricted to properly authorized individuals.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
17.01	Documents governing access to critical production systems and their supporting environment exist.	Inquired of IT management to determine whether documents governing access to critical production systems and their supporting environment exist. Inspected the documents governing logical and physical access to determine whether they were approved, maintained on the IESO's Intranet site and were periodically reviewed and updated when necessary.	No deviations noted.
17.02	There are defined roles and responsibilities for the approval and maintenance of user logical access within the access management process.	Inquired of IT management to determine whether there are defined roles and responsibilities for the approval and maintenance of user logical access within the access management process. Inspected the access management process documents to determine whether there are defined roles and responsibilities for the approval and maintenance of user logical access.	No deviations noted.
17.03	General configuration settings on operating systems and databases are used to enable logical access restrictions.	Inquired of IT management to determine whether general configuration settings on operating systems and databases are used to enable logical access restrictions. Inspected a sample of operating systems and databases general configuration settings to determine whether they enable logical access restrictions.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
17.04	User authentication is achieved through the use of a combination of password controls.	Inquired of IT management to determine whether user authentication is achieved through the use of a combination of password controls. Inspected a sample of critical production systems and supporting environments password controls to determine whether user authentication is achieved through the use of a combination of password controls.	No deviations noted.
17.05	Access to privileged IT functions is limited to appropriate individuals.	Inquired of IT management to determine whether access to privileged IT functions is limited to appropriate individuals. Inspected a sample of critical production systems to determine whether access to privileged IT functions is limited to appropriate individuals.	No deviations noted.
17.06	Privilege Stewards or Business process owners authorize the granting of access to critical production systems for new or modified logical user access privileges.	Inquired of IT management to determine whether privilege stewards or business process owners authorize the granting of access to critical production systems for new or modified logical user access privileges. Inspected a sample of new and modified user access requests to determine whether appropriate privilege steward or business process owner authorization was obtained and documented.	Deviation noted. For one (1) of forty (40) new and modified user access request, appropriate privilege steward or business process owner authorization was not obtained and documented. Refer to Management Response below.
17.07	Logical access privileges are revoked on a timely basis for staff departures.	Inquired of IT management to determine whether access privileges are revoked on a timely basis for staff departures. Inspected a sample of staff departures to determine whether logical access privileges were revoked on a timely basis.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
17.08	Logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or their delegates.	Inquired of IT management to determine whether logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or their delegates. Inspected a sample of critical production systems to determine whether the logical access privileges granted to users of critical production systems are reviewed periodically and approved by business process or system owners or their delegates.	Deviation noted. For one (1) of eighteen (18) periodic logical access privilege reviews sampled, inappropriate employee access was not detected and removed as part of the review. Refer to Management Response below.
17.09	Approving access, setting up access, and monitoring access violations and violation attempts are performed by different, appropriate individuals.	Inquired of IT management to determine whether approving requests to access systems, setting up access, and monitoring access violations and violation attempts are performed by different individuals. Inspected a sample of logical access requests to determine whether the tasks of approving access, setting up access, and monitoring access violation and violation attempts are performed by appropriate individuals.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
17.10	Unsuccessful attempts to access servers hosting critical production systems are monitored to detect possible intrusion.	Inquired of IT management to determine whether access attempts are monitored to detect repeated unauthorized access attempts to servers hosting critical production systems. Inspected a sample of servers hosting critical production systems security parameters to determine whether security logging was enabled. Inspected a sample of documented periodic reviews of security logs to determine whether the user access was monitored to detect possible intrusions and that repeated unauthorized access attempts were investigated.	No deviations noted.
17.11	Physical access to data centre facilities is restricted to authorized individuals by the use of a card key system.	Inquired of IT management to determine whether physical access to data centre facilities is restricted to authorized individuals by the use of a card key system. Observed that physical access to the data centre facilities is restricted to authorized individuals by the use of a card key system. Inspected a sample of individuals who have access to the data centre facilities to determine whether their access was authorized.	No deviations noted.
17.12	Management periodically reviews and approves physical access permissions.	Inquired of IT management to determine whether management periodically reviews and approves physical access permissions. Inspected a sample of periodic reviewed to determine whether management reviews and approved physical access permissions.	No deviations noted.

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	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
17.13	Market Participant data that is transmitted via market transactional systems are encrypted.	Inquired of IT management to determine whether Market Participant data that is transmitted via market transactional systems is encrypted. Inspected sample SFTP configuration to determine whether encryption is enabled.	No deviations noted.
17.14	Remote access by IESO staff to systems is controlled through encrypted VPN mechanisms using two factor authentication.	Inquired of IT management to determine whether remote access to systems is controlled through encrypted VPN mechanisms using two factor authentication. Inspected the configuration of the remote access system configuration to determine whether remote access to systems is controlled through encrypted VPN mechanisms using two factor authentication.	No deviations noted.

Management Response (Control 17.06 and Control 17.08)

The auditor's report identifies an instance where access was granted to an employee with a similar first name of the employee intended to be granted the access to specific application servers. The application servers are Linux-based systems, and for those specific systems it is possible, when provisioning users, to enter more than one user at a time based on a search of "firstname" in the account administration tool. Two employees, instead of one, were selected by the operator. By reviewing the home directories created on the servers, it was validated that the second employee, who was added in error, did not access the servers.

The IESO understands the importance of assigning the correct privileges to the employees that require those privileges, and that periodic reviews of access privileges are conducted with sufficient diligence such that appropriate access permissions are only granted to those employees who are authorized to have them.

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Control Objective 18: Backup & Recovery

Controls provide reasonable assurance that critical production systems and related data supporting settlement processes are properly backed-up so that they can be recovered in the event of a system outage or data integrity issue.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
18.01	Management has determined the time frame for restoration of critical production systems supporting business operations in the event of a disaster and has documented recovery plans that are responsive to this time frame.	Inquired of IT management to determine whether the time frame for business operations restoration of critical production systems in the event of a disaster has been determined and whether documented recovery plans are responsive to this time frame. Inspected the recovery plans to determine whether a defined time frame for the restoration of critical production systems in the event of a disaster has been documented.	No deviations noted.
18.02	The IT infrastructure at the primary site and the backup location includes environmental controls and backup power facilities to protect critical production systems against potential risks that might disrupt system operations and impair system availability.	Inquired of IT management to determine whether the primary site and the backup location includes environmental controls and backup power facilities to protect critical production systems against potential risks that might disrupt system operations and impair system availability. Inspected maintenance records for the critical production systems used at the primary site facilities and the backup location to determine whether environmental controls and backup power facilities are in place to protect critical production systems against potential risks that might disrupt system operations and impair system availability.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
18.03	A processing facility is maintained at a backup location for use in the event of a computer-related disaster.	Inquired of IT management to determine whether a processing facility is maintained at a backup location for use in the event of a computer-related disaster. Observed the processing facility at the backup location to determine whether it is maintained and available for use in the event of a computer-related disaster. Inspected contractual documentation for the backup processing facility to determine whether it is maintained and available for use in the event of a computer-related disaster.	No deviations noted.
18.04	Critical production data is replicated to equipment placed in operation at the backup location.	Inquired of IT management to determine whether critical production data is replicated to equipment placed in operations at the backup processing facility. Inspected a sample of system logs of critical production systems to determine whether replication of critical production data was successful.	No deviations noted.
18.05	Critical production systems are backed up daily.	Inquired of IT management to determine whether critical production systems are backed up daily. Inspected a sample of critical production systems backup logs to determine whether the systems were backed up daily.	No deviations noted.
18.06	Access to offline storage, backup data, systems and media is restricted to authorized personnel.	Inquired of IT management to determine whether access to offline storage, backup data, systems and media is restricted to authorized personnel. Inspected the physical access control system for the offline storage facility to determine whether physical and logical access to offline storage, backup data, systems and media was restricted to authorized personnel.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
18.07	Individuals who are responsible for configuring the automated backup schedule are not also responsible for monitoring the backup process.	Inquired of IT management to determine whether individuals who perform backups are not also responsible for monitoring them. Inspected the access rights of the individuals who have access to the backup systems to determine whether individuals responsible for configuring the automated backup schedule are not also responsible for monitoring the backup process. Inspected the IT organization charts and role definition documents to determine whether there are defined roles and responsibilities for the configuration and maintenance of the backup process.	Deviation noted. For 2 of 8 users with access to configure the automated backup schedule, they were also responsible for monitoring the backup process. Refer to Management Response below.
18.08	Procedures are in place for operating essential settlements processing functionality at a physically remote back-up site.	Inquired of IT management to determine whether procedures are in place for operating essential settlements processing functionality at a physically remote back-up site. Inspected the recovery plan to determine whether procedures are in place for operating essential settlements processing functionality at a physically remote back-up site.	No deviations noted.
18.09	IT staff periodically test the ability to operate systems at the backup site utilizing contingency plan procedures.	Inquired of IT management to determine whether IT staff periodically test the ability to operate systems at the backup site. Inspected recovery documentation to determine whether periodic testing of the ability to operate systems at the backup site was scheduled. Inspected a sample of recovery testing results to determine whether periodic testing of the ability to operate systems at the backup site was performed.	No deviations noted.

Management Response (Control 18.07)

The auditor's report identifies an instance where elevated access was granted to an employee to modify backup configurations. The IESO understands the importance of maintaining the appropriate access levels to those specified in the control objectives. As part of the Microsoft Exchange Cloud Migration Project that started in 2016, the need arose for the Exchange Administrator to create new Exchange backup configurations and modify existing Exchange backup configurations in support of this key infrastructure project. Consequently, a decision was made by management to elevate the privileges of the Tier 2 ITOPS Support Team (a total of 3 employees) to accommodate for that essential need. The two other employees had neither a need nor the technical skills to change backup configurations, and were solely tasked with monitoring backup completion reports as well as restoring backup files. An Audit Trail Report, that was provided, confirms that those two employees did not make any changes to backup jobs nor created new backup jobs. In addition, ongoing monitoring of the approved backup jobs, by the main backup administrator, was an additional control to ensure that no un-approved backup jobs or configurations were introduced during the project period. The project is still ongoing, and is expected to be completed by the end of Q3 2017. The Project Schedule demonstrates that there is a task that will be executed prior to the project closure to restore the level of access of the ITOPS Support Team to its original level prior to the start of the project.

Control Objective 19: Job Scheduling

Controls provide reasonable assurance that programs are executed as planned and deviations from scheduled processing are identified and resolved in a timely manner.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
19.01	Documented job processing schedules exist and have been approved.	Inquired of IT management to determine whether documented job processing schedules exist and have been approved. Inspected a sample job processing schedule to determine whether it was approved.	No deviations noted.
19.02	Changes to job schedules are authorized by system owners.	Inquired of IT management to determine whether changes to job schedules are authorized by Privilege Stewards. Inspected a sample of changes to job schedules to determine whether changes to job schedules were authorized by Privilege Stewards.	No deviations noted.
19.03	Job processing schedules are reviewed, assessed and approved according to the IT Change Management Process.	Inquired of IT management to determine whether job processing schedules are reviewed, assessed and approved according to the IT Change Management Process. Inspected a sample of changes to job processing schedules to determine whether job processing schedules are reviewed, assessed and approved according to the IT Change Management Process.	No deviations noted.
19.04	Logical access controls prevent changes to job schedules by unauthorized personnel.	Inquired of IT management to determine whether logical access controls prevent changes to job schedules by unauthorized personnel. Inspected a sample of critical production systems logical access settings to determine whether logical access controls prevent changes to job schedules by unauthorized personnel.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
19.05	Individuals who program / implement / monitor scheduling do not have conflicting duties.	Inquired of IT management to determine whether individuals who plan/implement/monitor scheduling do not have conflicting duties. Inspected a sample of job schedules to determine whether different individuals plan, implement, and monitor scheduling. Inspected documented roles and responsibilities to determine whether different individuals plan, implement, and monitor scheduling.	No deviations noted.
19.06	Job scheduling log results are reviewed by system operators and exceptions are followed up.	Inquired of IT management to determine whether job scheduling log results are reviewed by system operators and exceptions are followed-up. Inspected a sample of job schedule log results to determine whether system operators reviewed them and followed-up on jobs that did not run as scheduled.	No deviations noted.

Control Objective 20: Incident Management

Controls provide reasonable assurance that IT operations problems or incidents are identified, recorded, responded to, resolved or investigated, reviewed, and analyzed in a timely manner.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
20.01	Documented problem identification and escalation procedures exist and are communicated to relevant personnel for use in the event of a production problem.	Inquired of IT management to determine whether documented problem identification and escalation procedures exist and are communicated to relevant personnel for use in the event of a production problem. Inspected the problem identification and escalation procedures to determine whether they exist and are communicated to relevant personnel for use in the event of a production problem.	No deviations noted.
20.02	Processing deviations, abnormal conditions and errors are identified, recorded and assigned to appropriate personnel for follow up and resolution.	Inquired of IT management to determine whether processing deviations, abnormal conditions and errors are identified, recorded and assigned to appropriate personnel for follow-up and resolution. Inspected a sample of problem and incident management tickets to determine whether processing deviations, abnormal conditions and errors were identified, recorded and assigned to appropriate personnel for follow-up and resolution.	No deviations noted.
20.03	Critical problems or incidents are responded to, analyzed and resolved in a timely manner.	Inquired of IT management to determine whether critical problems or incidents are responded to, analyzed and resolved timely. Inspected a sample of critical problem and incident management tickets to determine whether critical problems or incidents were responded to, analyzed and resolved timely.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
20.04	Management reviews recorded significant processing deviations and errors periodically.	Inquired of IT management to determine whether management reviews recorded significant processing deviations and errors periodically. Inspected a sample of reports of significant processing deviations and errors to determine whether reviews were performed by management.	No deviations noted.
20.05	The IESO has on shift staff to monitor critical production systems on a 24x7 basis.	Inquired of IT management to determine whether staff are scheduled to monitor critical production systems on a 24x7 basis. Inspected the shift schedule to determine whether staff are scheduled on a 24x7 basis to monitor critical production systems.	No deviations noted.

Control Objective 21: Third Party Service Provider Monitoring

Controls provide reasonable assurance that third party services are monitored for the design and operating effectiveness of the third party services' controls.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
21.01	IT management review the scope, control objectives, and control descriptions of the Wallstreet Treasura System service organization report, on an annual basis, to ensure the report identifies all internal controls relevant to change management, logical and physical access management, backup and recovery, job scheduling, and problem and incident management.	Inquired of IT management to determine whether IT management review the scope, control objectives, and control descriptions of the Wallstreet Treasura System service organization report, on an annual basis, to ensure the report identifies all internal controls relevant to change management, logical and physical access management, backup and recovery, job scheduling, and problem and incident management. Inspected evidence of review by IT management to determine whether IT management review the scope, control objectives, and control descriptions of the Wallstreet Treasura System service organization report, on an annual basis, to ensure the report identifies all internal controls relevant to change management, logical and physical access management, backup and recovery, job scheduling, and problem and incident management.	No deviations noted.

	Controls Specified by the IESO	Tests Performed by Ernst & Young LLP	Results of Tests
21.02	IT management review the audit opinion and any exceptions included in the Wallstreet Treasura System service organization report, on an annual basis, and follow up with Wallstreet Systems management to identify compensating controls, if necessary, to mitigate associated risks.	Inquired of IT management review the audit opinion and any exceptions included in the Wallstreet Treasura System service organization report, on an annual basis, and follow up with Wallstreet Systems management to identify compensating controls, if necessary, to mitigate associated risks. Inspected evidence of review by IT management to determine whether IT management review the audit opinion and any exceptions included in the Wallstreet Treasura System service organization report, on an annual basis, and follow up with Wallstreet Systems management to identify compensating controls, if necessary, to mitigate associated risks.	No deviations noted.

Other Information Provided by the IESO

System Updates Post Audit Period

A project to refresh the Online Settlement Form (ONLSF) application is scheduled outside of the CSAE 3416 audit period which aims to automate settlement processes related to submission of settlement information. The IESO has invested considerable effort in standardizing the interface used by external participants, and that will be considered and leveraged in this project. This project will migrate ONLSF functionality to reliable and efficient IT solutions which in turn will improve corporate resilience.

The Surveillance Data Repository (SDR) will be replaced with a vendor supported Data Warehouse. This project is scheduled outside of the CSAE 3416 audit period. The new Data Warehouse will help to address purging and confidentiality requirements of the Information Management Policy.

Charge and Credit Codes

The table below lists the various charge and credit types used by the IESO during the period from January 1, 2017 to June 30, 2017. Some of these charges and credits are calculated automatically by our systems; others are calculated manually. Every charge and credit can be calculated manually depending on the circumstances. The description below contains our standard code for each charge/credit.

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
52	TRANSMISSION RIGHTS AUCTION SETTLEMENT DEBIT	Yes	Yes
100	NET ENERGY MARKET SETTLEMENT FOR GENERATORS AND DISPATCHABLE LOAD	Yes	Yes
101	NET ENERGY MARKET SETTLEMENT FOR NON-DISPATCHABLE LOAD	Yes	Yes
102	TR CLEARING ACCOUNT CREDIT	-	Yes
103	TRANSMISSION CHARGE REDUCTION FUND	Yes	Yes
104	TRANSMISSION RIGHTS SETTLEMENT CREDIT	Yes	Yes
105	CONGESTION MANAGEMENT SETTLEMENT CREDIT FOR ENERGY	Yes	Yes
106	CONGESTION MANAGEMENT SETTLEMENT CREDIT FOR 10 MINUTE SPINNING RESERVE	Yes	Yes

Filed: September 7, 2017, EB-2017-0150, Exhibit I, Tab 5.1, Schedule 2.21 BOMA 21, Attachment 1

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
107	CONGESTION MANAGEMENT SETTLEMENT CREDIT FOR 10 MINUTE NON-SPINNING RESERVE	Yes	Yes
108	CONGESTION MANAGEMENT SETTLEMENT CREDIT FOR 30 MINUTE OPERATING RESERVE	Yes	Yes
122	RAMP-DOWN SETTLEMENT AMOUNT	Yes	-
135	REAL-TIME IMPORT FAILURE CHARGE	Yes	Yes
136	REAL-TIME EXPORT FAILURE CHARGE	Yes	Yes
144	REGULATED NUCLEAR GENERATION ADJUSTMENT AMOUNT	Yes	Yes
147	CLASS A GLOBAL ADJUSTMENT SETTLEMENT AMOUNT	Yes	Yes
148	CLASS B GLOBAL ADJUSTMENT SETTLEMENT AMOUNT	Yes	Yes
150	NET ENERGY MARKET SETTLEMENT UPLIFT	Yes	Yes
155	CONGESTION MANAGEMENT SETTLEMENT UPLIFT	Yes	Yes
169	STATION SERVICE REIMBURSEMENT DEBIT	-	Yes
170	LOCAL MARKET POWER REBATE	-	Yes
183	GENERATION COST GUARANTEE RECOVERY DEBIT	-	Yes

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
186	INTERTIE FAILURE CHARGE REBATE	Yes	Yes
194	REGULATED NUCLEAR GENERATION BALANCING AMOUNT	Yes	Yes
196	GLOBAL ADJUSTMENT BALANCING AMOUNT	Yes	Yes
197	GLOBAL ADJUSTMENT-SPECIAL PROGRAMS BALANCING AMOUNT	Yes	Yes
200	10-MINUTE SPINNING RESERVE MARKET SETTLEMENT CREDIT	Yes	Yes
202	10-MINUTE NON-SPINNING RESERVE MARKET SETTLEMENT CREDIT	Yes	Yes
204	30-MINUTE OPERATING RESERVE MARKET SETTLEMENT CREDIT	Yes	Yes
250	10-MINUTE SPINNING MARKET RESERVE HOURLY UPLIFT	Yes	Yes
252	10-MINUTE NON-SPINNING MARKET RESERVE HOURLY UPLIFT	Yes	Yes
254	30-MINUTE OPERATING RESERVE MARKET HOURLY UPLIFT	Yes	Yes

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
450	BLACK START CAPABILITY SETTLEMENT DEBIT	-	Yes
451	HOURLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	Yes	Yes
452	MONTHLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	Yes	Yes
454	REGULATION SERVICE SETTLEMENT DEBIT	-	Yes
600	NETWORK SERVICE CREDIT	Yes	Yes
601	LINE CONNECTION SERVICE CREDIT	Yes	Yes
602	TRANSFORMATION CONNECTION SERVICE CREDIT	Yes	Yes
603	EXPORT TRANSMISSION SERVICE CREDIT	Yes	Yes
650	NETWORK SERVICE CHARGE	Yes	Yes
651	LINE CONNECTION SERVICE CHARGE	Yes	Yes
652	TRANSFORMATION CONNECTION SERVICE CHARGE	Yes	Yes
653	EXPORT TRANSMISSION SERVICE CHARGE	Yes	Yes
702	DEBT RETIREMENT CREDIT	Yes	Yes

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
703	RURAL RATE SETTLEMENT CREDIT	Yes	Yes
752	DEBT RETIREMENT CHARGE	Yes	Yes
753	RURAL RATE SETTLEMENT CHARGE	Yes	Yes
1050	SELF-INDUCED DISPATCHABLE LOAD CMSC CLAWBACK	Yes	Yes
1051	RAMP-DOWN CMSC CLAW BACK	Yes	-
1131	INTERTIE OFFER GUARANTEE SETTLEMENT CREDIT	Yes	Yes
1135	DAY-AHEAD IMPORT FAILURE CHARGE	Yes	Yes
1136	DAY-AHEAD EXPORT FAILURE CHARGE	Yes	Yes
1315	DEMAND RESPONSE CAPACITY OBLIGATION - AVAILABILITY CHARGE	Yes	Yes
1401	INCREMENTAL LOSS SETTLEMENT CREDIT	Yes	Yes
1403	SPEED-NO-LOAD SETTLEMENT CREDIT	Yes	Yes
1404	CONDENSE UNIT START-UP AND OM&A SETTLEMENT CREDIT	Yes	Yes

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
1405	HOURLY CONDENSE ENERGY COSTS SETTLEMENT CREDIT	Yes	Yes
1406	MONTHLY CONDENSE ENERGY COSTS SETTLEMENT CREDIT	Yes	Yes
1407	CONDENSE TRANSMISSION TARIFF REIMBURSEMENT SETTLEMENT CREDIT	Yes	Yes
1408	CONDENSE AVAILABILITY COST SETTLEMENT CREDIT	Yes	Yes
1451	INCREMENTAL LOSS OFFSET SETTLEMENT AMOUNT	Yes	Yes
1470	ONTARIO ELECTRICITYSUPPORT PROGRAM BALANCING AMOUNT	Yes	Yes
1500	DAY-AHEAD PRODUCTION COST GUARANTEE PAYMENT - COMPONENT 1 AND COMPONENT 1 CLAWBA	Yes	Yes
1501	DAY-AHEAD PRODUCTION COST GUARANTEE PAYMENT - COMPONENT 2	Yes	Yes
1502	DAY-AHEAD PRODUCTION COST GUARANTEE PAYMENT - COMPONENT 3 AND COMPONENT 3 CLAWBA	Yes	Yes

Charge Type ID	Charge Type Name	Automatic Charge	Semi-Automated or Manual Line Item
1503	DAY-AHEAD PRODUCTION COST GUARANTEE PAYMENT - COMPONENT 4	Yes	Yes
1504	DAY-AHEAD PRODUCTION COST GUARANTEE PAYMENT - COMPONENT 5	Yes	Yes
1505	DAY-AHEAD PRODUCTION COST GUARANTEE REVERSAL	Yes	Yes
1510	DAY-AHEAD GENERATORWITHDRAWAL CHARGE	Yes	Yes
1550	DAY-AHEAD PRODUCTION COST GUARANTEE RECOVERY DEBIT	Yes	Yes
1560	DAY-AHEAD GENERATORWITHDRAWAL REBATE	Yes	Yes
1650	FORECASTING SERVICEBALANCING AMOUNT	-	Yes
9920	ADJUSTMENT ACCOUNT CREDIT	Yes	Yes
9990	IESO ADMINISTRATION CHARGE	Yes	Yes

List of Acronyms

AGC	Automatic Generation Control
AQEW	Allocated Quantity of Energy Withdrawn
CAB	Change Advisory Board
CEO	Chief Executive Officer
CMSC	Congestion Management Settlement Credit
COWZ	Constrained off Watch Zone
CRS	Commercial Reconciliation System
DA-PCG	Day-Ahead Production Cost Guarantee
EMS	Energy Management System
ERM	Enterprise Risk Management
ETT	Export Transmission Tariff
GCG	Generation Cost Guarantee
GSSR	Generation Station Service Rebate
HOEP	Hourly Ontario Energy Price
ICG	IESO-controlled grid

IESO	Independent Electricity System Operator
IOG	Intertie Offer Guarantee
ITIL	Information Technology Infrastructure Library
LMP	Local Market Power
MACD	Market Assessment and Compliance Division
MAU	Market Assessment Unit
MCP	Market Clearing Price
MEC	Measurement Error Correction
MIM	Market Information Management system
MMP	Metered Market Participant
MPI	Market Participant Interface
MSP	Metering Service Provider
MTR	Meter Trouble Reporting
MFT	Managed File Transfer
NERC	North American Electricity Reliability Corporation
NOD	Notice of Disagreement

OPA	Ontario Power Authority
OPG	Ontario Power Generation Inc.
PIN	Personal Identification Number
RFC	Request for Change
RSVC	Reactive Support and Voltage Control
RTDH	Real Time Data Historian
RT-GCG	Real Time Generation Cost Guarantee
RTUS	Remote Terminal Units
SCADA	Supervisory Control and Data Acquisition
SDR	Surveillance Data Repository
SLA	Service Level Agreement
SMO	Segregated Mode of Operation
SSM	System Security Monitor
TRA	Transmission Rights Auction system
TTDC	Transmission Tariff Demand Calculator
VPN	Virtual Private Network

Review of the Real-Time Dispatch Algorithm

Prepared for Independent Electricity System Operator

May 30, 2016

May 30, 2016

Julia McNally
Director, Internal Audit
Independent Electricity System Operator
2635 Lakeshore Road West
Mississauga, ON
L5J 4R9

Dear Ms. McNally:

Subject: Independent Review of the Real-Time Algorithm used in the Ontario Electricity Market

The Independent Electricity System Operator ("IESO") oversees the safe, sustainable and reliable operation of Ontario's power system. This includes the responsibility for managing Ontario's wholesale electricity market, through which the supply and demand for electricity are kept in balance and the Hourly Ontario Energy Price is set.

In accordance with Market Rule 7.4.2.4, IESO commissions an independent review of the operation and application of the dispatch algorithm and related dispatch processes and procedures at least once every two calendar years. PwC last performed an independent review of the dispatch algorithm in 2014.

The objective of this review was to assess the compliance of the real-time dispatch algorithm with the following applicable Market Rules in accordance with the standards set out in Section 8600 (Reviews of Compliance with Agreements and Regulations) of the Chartered Professional Accountants Canada Handbook:

- Chapter 7, Section 4 (The Dispatch Algorithm)
- Appendix 7.5 (The Market Clearing and Pricing Process)

This report communicates the results of the review performed by PwC, as of our test day, February 23, 2016.

Yours truly,

Brian Poth
Power & Utilities Principal

Contents

A. Introduction

Background

The Independent Electricity System Operator (IESO) is responsible for operating Ontario's power system and electricity market to ensure an adequate, reliable and secure supply of energy for the province in the short and long term.

A key part of IESO's role is to administer the operation of the wholesale electricity market to ensure that the dispatch of least cost generation and load facilities for energy and reserve and to maintain the power flows on transmission facilities within security and operational limits. The wholesale electricity market operates operates in pre-dispatch (i.e. hourly) and real-time (i.e. every 5 minutes) to set the market clearing price (MCP) and to dispatch instructions specificying the required amount of energy to be injected (by sellers) or withdrawn (by buyers) based on their accepted offers and bids.

Efficient operation of the electricity market requires that the demand of the system be met with the lowest price generation and operating reserve dispatch as possible, given the bids and offers submitted and applicable constraints on the use of the IESO controlled grid. The dual goals of market efficiency and system security require the solution of a constrained optimization problem: minimizing the cost of generation and reserves, subject to meeting required demand and security constraints.

The IESO has modeled the pre-dispatch and real-time dispatch algorithm into the Dispatch and Scheduling Optimization (DSO), to determine the most efficient dispatch of resources subject to the constraints for secure operation of the grid.

The dispatch algorithm and related dispatch processes and procedures are complex and specialized processes. Accordingly, we have written this report to provide.

- An overview of the dispatch algorithm (the DSO);
- The specific scope of our review and review approach;
- Our formal report setting out the results of our review;
- IESO management interpretations applicable to our review; and
- Appendices containing the relevant Market Rules that were reviewed.

Overview of DSO

The DSO is a dedicated software program that runs the dispatch algorithm to determine the most efficienct dispatch of resources subject to the constraints for secure operation of the grid. The inputs, proceses and outputs of the DSO are described below. Further detail can be found in Appendix A.

Inputs to the DSO

Inputs to the DSO consist of generator offers, import offers, dispatchable load bids, export bids, technical data, outage information and forecasts from non-dispatchable resources.

Data sources include the Market Operations System (MOS), Energy Management System (EMS), Outage Scheduler (OS), Demand Forecast System (DFS), Resource Dispatch (RD), Dispatch Data Management System (DDMS), Centralized Forecasting System Database (CFSDB) and Tie-Breaking Modifier Database (TBMD). The mathematical formulation for the dispatch algorithm is described in section 4 of Chapter 7 and specified in Appendix 7.5 of the market rules.

Operation of the DSO

The DSO produces dispatch schedules and settlement prices to determine the most efficient dispatch of resources subject to the constraints for secure operation of the grid by applying an optimization program. The optimization program considers many factors from market participants such as bids and offers of energy and operating reserve, and those provided by the IESO such as the model of the transmission system. Figure 1 provides a simple overview of the overall process.

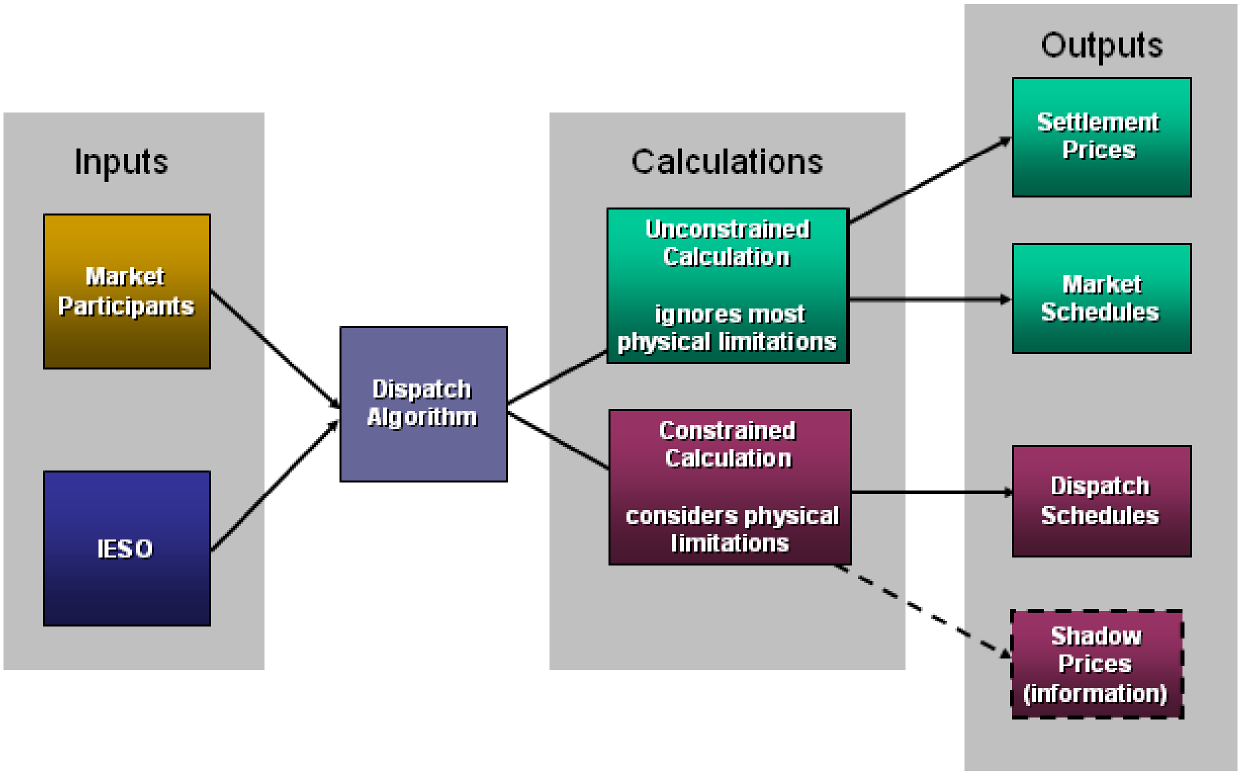


Figure 1: Overview of the DSO[1]

The IESO uses the DSO to solve the constrained optimization problem by running the DSO in two different timeframes as follows:

Pre-Dispatch

The IESO uses the DSO to produce pre-dispatch constrained schedules and projected market prices which in turn facilitates the efficient and reliable operation of the market by allowing participants to anticipate conditions for the coming hours and next day.

The DSO is run hourly in 'pre-dispatch' in both the constrained and unconstrained modes. Pre-dispatch determines projected prices and schedules over a number of future hours. It also determines schedules for imports and exports for the next hour. With the exception of inter-tie prices, the pre-dispatch market prices are not financially binding.

Real-Time

The IESO also uses the DSO to produce real-time constrained schedules and real-time market schedules and prices. The real-time schedules reflect the actual generation, reserve allocation and dispatchable load levels that achieve secure operation at a minimum cost, subject to the system operator's assessment of the reliability of the network. The IESO issues dispatch instructions according to the real-time schedules. The real-time market prices are used, unless administered prices are necessary, to settle the market.

Further, the DSO is run in two different modes:

[1] Source: Introduction to Ontario's Physical Markets, IESO

Constrained Mode	Unconstrained Mode
Looks forward to determine what resources need to be dispatched to meet the demand for the next interval.	Looks backwards to the interval that just ended in order to determine the price and market schedules for that interval.
Considers all physical limitations of the system: considers the detailed generation and transmission circuit relationships, losses associated with moving electricity through the system and security constraints.	Ignores most physical limitations of the system inside Ontario.
Produces dispatch instructions that are dispatched to resources and informational shadow prices.	Produces settlement prices (Market Clearing Price) and informational market schedules.

The Unconstrained mode allows the DSO to determine market economics by developing a market clearing price that is the same for all load and generation throughout the province (i.e. whereby losses or other restrictions that can cause prices to differ from location to location on the grid are ignored).

The Constrained mode allows the DSO to determine how to dispatch facilities by considering both economics along with the actual physical characteristics of the grid in order to respect system limitations.

Deviations to DSO Output

There are certain circumstances where the actual dispatch instructions are different from the outputs of the DSO runs. Market Rules 4.2.2 and 7.2.1 permit the IESO to intervene with the outcome of the dispatch algorithm and modify or override the dispatch instructions produced by the DSO for reasons related to system reliability (i.e. security and adequacy). Market Rule 4.2.3 requires the IESO to report significant differences between these manual interventions and the results of the dispatch algorithm on a monthly basis and to provide reasons for all interventions.

A "Dispatch Deviation" is defined as a dispatch instruction that differs from the resource's real-time schedule as determined by the DSO. Dispatch Deviations can occur as a result of automated filtering or manually through verbal instruction of resources or by manual overrides (i.e. overrides to the DSO output) by Control Room operators.

Automated Dispatch Deviations

Automated Dispatch Deviations occur as follows:

- The IESO uses the outputs of the constrained DSO to determine the dispatch instructions that guide actual physical operation of the electricity system. An automatic filter in the Resource Dispatch (RD)[2] application ensures that the energy schedule created by the DSO is only used to revise the dispatch instructions to a resource when the revision exceeds the greater of +/-10 MW or 2% of the past dispatch instruction. However, there are three circumstances where dispatch instructions to a resource can be automatically revised even when the change falls within the RD filter threshold, as follows:
  - To ensure energy resources are correctly dispatched to its high operating limit, or its low operating limit;
  - For provision of energy reduction change when the previous dispatch instructions is higher than its current maximum offer; and
  - For interval 1 and 7 of each dispatch hour when filtering is turned off to ensure small recurring increments or decrements of energy that have been legitimately offered by market participants are issued dispatch instructions on the hour and the half hour.

[2] Resource Dispatch (RD) is the application that reflects the actual dispatch instructions that were sent to market participants (i.e. the schedule determined by the DSO plus any dispatch deviations that occurred).

- The automated Dispatch Deviations as described above, are not reported.

Manual Dispatch Deviations

Adjustments are generally applied by control room personnel in real-time by:

1. **Blocked Dispatches** – modification of schedules produced by dispatch algorithm by removing one or more resources from the RD application's merit order (i.e. the schedule or "offer stack").
2. **One Time Dispatches –** verbal instruction of resources; occur when one or more Energy resources offers/bids (not based on merit order cleared offers) are selected for dispatch (not based on merit order cleared offers) to resolve a problem that was not known when the dispatch algorithm was run. One time dispatches may be electronically sent via RD or through a direct verbal instruction over the telephone. One time dispatches may require a resource to increase or decrease their output, depending on circumstances.

Both of the above manual Dispatch Deviations (Blocked Dispatches and One-Time Dispatches) are reported to market participants and categorized by one of the eight rationale for taking these actions, as follows:

- The action was required to correct for recognized non-compliance with dispatch instructions by a Market Participant(s);
- The action was taken to respect an Operating Security Limit due to differences in the forecast and actual flows;
- The action was taken to respect the forecasted (greater than 5 minutes) Operating Reserve requirement;
- The action was taken to correct an over / under generation condition (ACE);
- The action was taken to mitigate the effects of operational data input failures;
- The action was taken to facilitate a planned equipment outage;
- The action was taken to mitigate the effects of dispatch algorithm input errors; or
- The action was taken to preserve resource adequacy for future energy needs.

B. Objective and Scope of Review

Objective

In accordance with Market Rule 7.4.2.4, the IESO commissions an independent review of the operation and application of the dispatch algorithm and related dispatch processes and procedures at least once every two calendar years. PricewaterhouseCoopers LLP was contracted to perform this review in 2016 through a competitive procurement.

The purpose of this review was to confirm that the dispatch algorithm and related dispatch processes and procedures are in compliance with section 4 of Chapter 7 and Appendix 7.5 of the market rules. This report communicates the results of the review.

Scope of Review

Our review addressed the IESO's compliance with Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules. Since section 4.2 of Chapter 7 allows the IESO to manually modify the results of the DSO and requires the IESO to report the reasons for discrepancy between manual dispatch instructions and the outputs of the dispatch algorithm, the manual overrides and reporting are also within scope for this review.

The scope of our review for the DSO is outlined below. Further detail can be found in Appendix A.

Scope Inclusions

Our review was performed to assess the operation of the DSO to produce real-time schedules, both in the Constrained and Unconstrained mode for our test day, February 23, 2016.

For both of these modes in real-time, our review considered the outputs of the DSO including determination of real-time resource limits (i.e. ramp rate limits, maximum generation capacity), the economic optimality of DSO-produced schedules (generator equilibrium pricing, dispatchable loads equilibrium pricing), the co-optimization of energy and operating reserve and the determination of the Market Clearing Price.

We also reviewed pre-dispatch schedules produced to forecast energy and determine imports/exports for the next hour. Additionally, we reviewed manual overrides to the outputs of the DSO.

Scope Exclusions

The completeness and accuracy of the inputs to the DSO was outside of the scope of this review. For clarity, this also excludes manual adjustments of the inputs to the DSO.

Further, the internal processes of the DSO including the estimation of Non-Dispatchable Load (NDL) and system losses (dynamic) were outside the scope of our review as they are dependent on the network design model that represent the IESO grid.

The following outputs of the DSO were also out of scope:

- Obligation indicator Index (OII)
- Flow-limited transmission circuits
- System operating reserve requirements

Limitations of Review

We performed our review in accordance with section 8600 of Chartered Professional Accountants Canada Handbook "Review of Compliance with Agreements and Regulations". In the case of the DSO review, Agreements and Regulations were section 4 of Chapter 7 and Appendix 7.5 of the IESO Market Rules. Where required, PwC obtained IESO management's interpretations to the rules in order to clarify the requirements and interpretations of the Market Rules.

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 IESO'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.

C. PwC's Review Approach

Our approach to the DSO review was to assess the DSO output schedules for energy and operating reserve from both the Constrained and the Unconstrained sequence for violations of the in-scope market rules. This approach allowed us to review all resources in the IESO controlled grid for all 288 intervals of our test day.

Specifically, our review of the Dispatch Algorithm included the following activities:

Market Rule Review

We gained an understanding of the applicable Market Rules, and related processes and procedures by:

- Reviewing the DSO procedural documentation including IESO Market Rules, Market Manuals and Vendor Change Requests.
- Interviewing IESO personnel responsible for the use, operation, maintenance and monitoring of the DSO.
- Reviewing procedural documentation and the management practice of manual overrides to the DSO output.

Control Room Observation

We observed control room operations in real-time for the morning ramp period of our test day to assess procedures for manual intervention by control room and identify manual overrides to the DSO output, as described in Section A. Introduction, of this report.

Information Validation

We validated the information provided by the IESO and used for testing (inputs and outputs of the DSO for our test day) by comparing a sample interval of the historical data obtained from the IESO to the save case within the DSO.

Additionally, we compared the outputs provided (resource schedules and market clearing prices) to the summarized information published on the IESO public web site for our test day.

Where required, we obtained management's interpretations to clarify the requirements and interpretations of the Market Rules.

Automated Testing

We developed and executed Automated Screening Tests to assess the DSO generated schedules compliance with market rules related to operations limits as well as assess the overall DSO computed schedules' economic feasibility. The key activities included:

- Developing and executing 49 automated tests to assess compliance of DSO output with the mathematical limits and representations in Appendix 7.5 of the Market Rules.
- Screening the DSO schedules for February 23, 2016 to identify individual dispatches that were sub-optimal or in violation of the unit's limits or the security constraints.
- Reviewing management interpretations and/or archived historical outputs of the DSO for conditions in direct violation of limits defined in the Market Rules. For instance, Market Rule 6.5 of Appendix 7.5 describes the up and down ramp limits that are applied and which may be in conflict with available operating limits of a resource.
- Developing screens that tested other implications of the Market Rules.

Scenario Testing

For Market Rules that were not triggered on the test day or were not covered by automated testing, we developed and performed "scenario tests" using base case and save case data as follows:

- Tests were performed in IESO testing environment by manipulating inputs and observing whether the outputs produced by the DSO are as expected.
- Performed 5 Base Case/Save Case tests in the testing environment with IESO personnel executing the tests and PwC observing the effects of modifying inputs on the resulting DSO solution.

Testing of Manual Dispatch Deviations

We reviewed the manual overrides to the DSO output to confirm that the IESO reports all significant differences between dispatch instructions issued and the results of the dispatch algorithm in the published monthly report.

D. Results of Review

Independent Reviewer's Report

May 30, 2016

To the IESO Board of Directors:

We have reviewed the Independent Electricity System Operator (IESO)'s, compliance on February 23, 2016, with Chapter 7.4 (The Dispatch Algorithm), dated June 3, 2015 and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules, dated December 2, 2015, as interpreted by IESO Management and captured in the DSO including related processes and procedures.

Management's interpretations of the Market Rules are set out on the following page (page 10) and the relevant sections of the Market Rules are attached in the Appendices of this report. Our review was made in accordance with Canadian generally accepted standards for review engagements and accordingly consisted primarily of enquiry, analytical procedures, and discussion related to information supplied to us by the IESO. Our review process and criteria are further described in Section C of the report.

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 dispatch algorithm was not in compliance, as at February 23, 2016, with Chapter 7.4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the Market Rules, inclusive of the interpretations made by IESO management described on the following page of our report.

PricewaterhouseCoopers LLP

Toronto, Ontario, Canada

Management Interpretations of Chapter 7.4 and Appendix 7.5 of the Market Rules

Unit Constraints

Appendix Chapter 7.5 Section 6.1.3 states that: Generationg ≥ EnergyOfferMing. This inequality requires that the scheduled energy not be less than the low operating limit associated with this energy offer.

Appendix Chapter 7.5 Section 6.1.4 states that: Generationg + ΣReserve r(g),c ≤ EnergyOfferMaxg. This inequality requires that the total amount of scheduled energy and operating reserve not exceed the high operating limit associated with this energy offer.

High and low operating limits are determined based on a combination of parameters, which include: offered energy capacity, outages, derates, operational constraints, wind/solar forecasts and minimum loading points.

Appendix Chapter 7.5 Section 6.5.2 states that: Generationg < GenerationEndMaxg and Generationg > GenerationEndMing requiring that the total amount of energy scheduled be within the maximum ramping up and ramping down capacity of the unit.

These inequalities do not have a violation variable associated with them and therefore, cannot be relaxed when in conflict with another inequality. As such, while the Market Rules referenced above specify the DSO will respect offered operating limits and ramp rates, there is a superseding merit order of constraints as operating limits and then ramp rates.

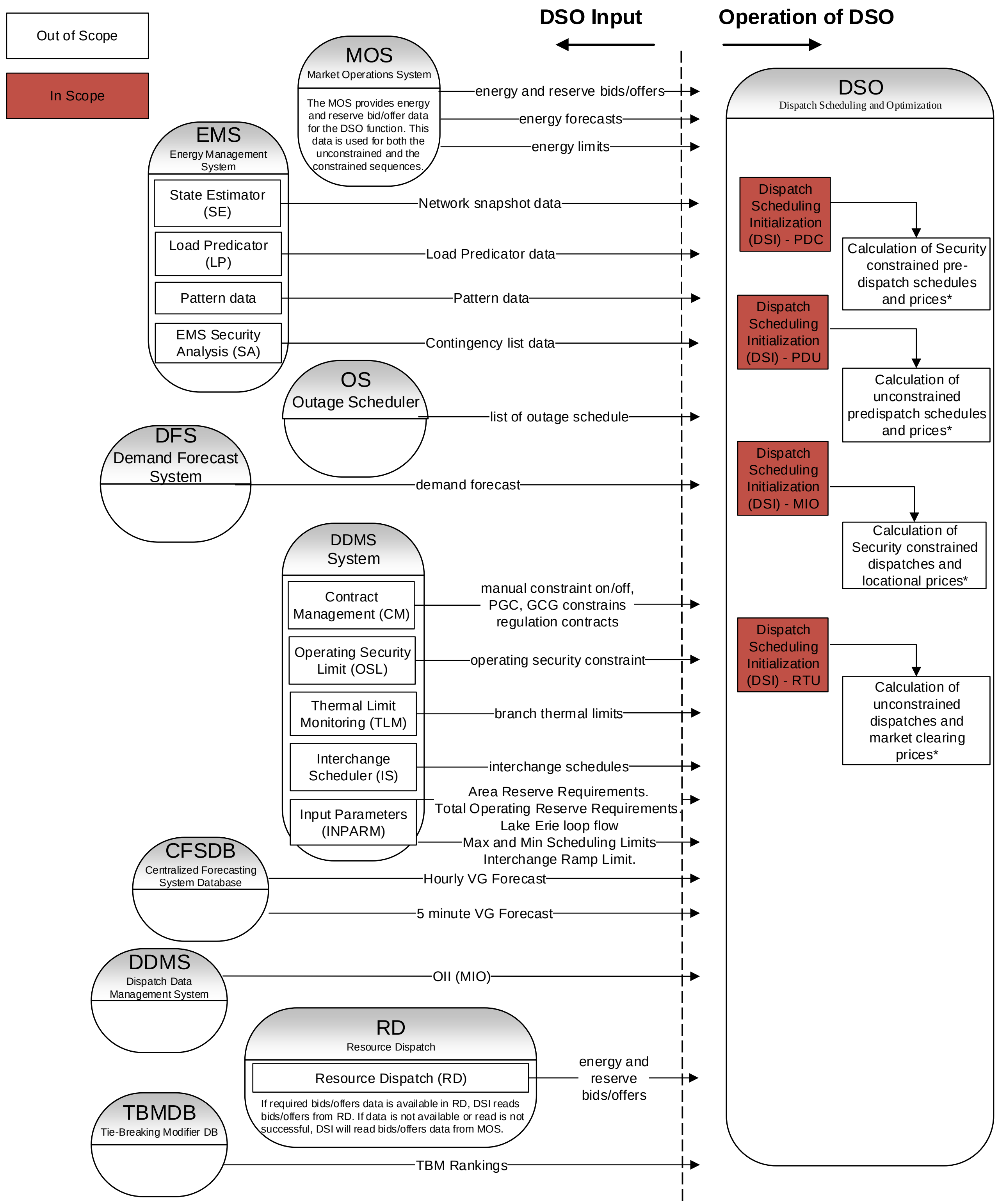
Dispatch Deviations

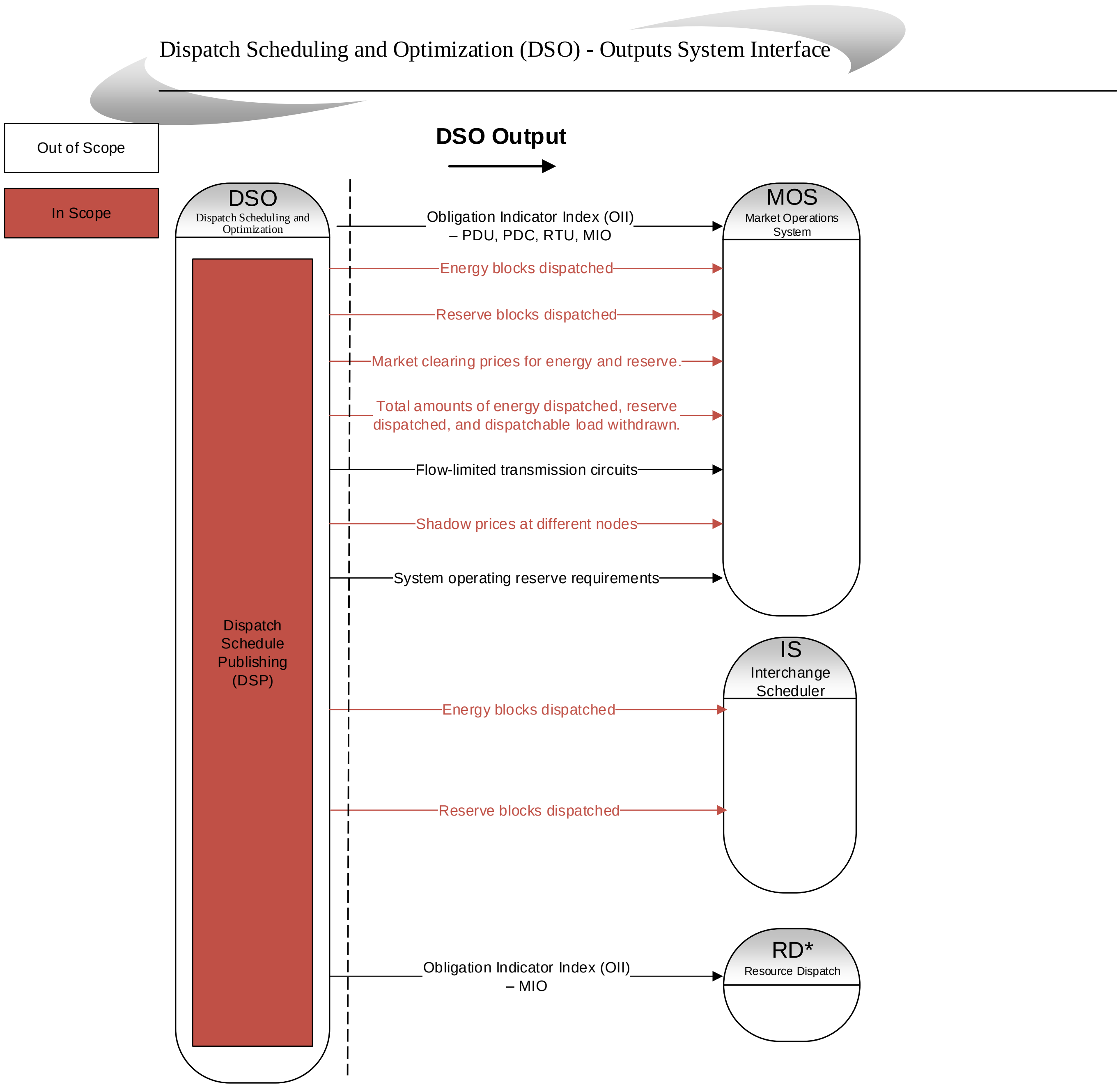
Where Chapter 7.4 and Appendix 7.5 refer to the differences between the results of the dispatch algorithm and the dispatch instructions issued, these refer to differences in addition to those automatically filtered. An automatic filter ensures that the energy schedule created by the DSO is only used to revise the dispatch instructions to a resource when the revision exceeds the greater of +/-10 MW or 2% of the last dispatch instruction that was issued to that resource.

Appendices

Appendix A – Dispatch Scheduling and Optimization (DSO) Inputs and Outputs

Dispatch Scheduling and Optimization (DSO) - Inputs System Interface




Dispatch Scheduling and Optimization (DSO) - Outputs System Interface
Out of Scope
In Scope
DSO Output
DSO
Dispatch Scheduling and Optimization
Dispatch Schedule Publishing (DSP)
Obligation Indicator Index (OII) – PDU, PDC, RTU, MIO
Energy blocks dispatched
Reserve blocks dispatched
Market clearing prices for energy and reserve.
Total amounts of energy dispatched, reserve dispatched, and dispatchable load withdrawn.
Flow-limited transmission circuits
Shadow prices at different nodes
System operating reserve requirements
MOS
Market Operations System
Energy blocks dispatched
Reserve blocks dispatched
IS
Interchange Scheduler
Obligation Indicator Index (OII) – MIO
RD*
Resource Dispatch

Appendix B – Chapter 7.4 – The Dispatch Algorithm

4.1 Purpose of the Dispatch Algorithm

4.1.1 The *IESO* shall determine the various schedules and prices required by this Chapter to be developed by it using a *dispatch algorithm* based on the mathematical techniques of constrained optimisation. The form and use of this *dispatch algorithm* are summarised in this section 4 and detailed in Appendix 7.5.

4.2 Uses of the Dispatch Algorithm

4.2.1 The *IESO* may use different numerical values in, or different computerised versions of, the *dispatch algorithm* for each of the several purposes described in this Chapter, but shall keep the objective, mathematical formulation and solution procedures the same, except as specifically noted.

4.2.2 The *IESO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7.

4.2.3 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *dispatch algorithm*.

4.2.4 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *dispatch algorithm* and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the related *dispatch* processes and procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004.

4.3 The Optimisation Objective

4.3.1 The *dispatch algorithm* shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as defined in section 4.3.2.

4.3.2 The economic gain from trade shall be defined as the difference between the value of the electricity produced (as indicated by the *energy demand* from *non-dispatchable loads* and the *energy bids* from *dispatchable loads*) and the cost of producing that electricity (as indicated by the *offers* to supply the *energy* and *operating reserves* necessary to *reliably* deliver that electricity to loads).

4.3.3 Maximising the economic gain from trade will determine quantities and prices that "clear the market," in the sense that, given the market-clearing prices and the *dispatch data*, no *market participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any *physical service*.

4.4 Inputs to the Dispatch Algorithm

4.4.1 The *IESO* shall use as inputs to the *dispatch algorithm* the data and information outlined in section 4.4 and described in more detail in Appendix 7.5.

4.4.1A [Intentionally left blank]

4.4.2 The cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on the most recent valid *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to *dispatchable generation facilities* and *dispatchable load facilities*.

4.4.3 Subject to section 4.4.3A, the price-insensitive load to be met shall be the sum of:

4.4.3.1 the net energy injections (injections minus withdrawals) by all *non-dispatchable load facilities*, *self-scheduling generation facilities* and *intermittent generators* and *transitional scheduling generators*; and

4.4.3.2 any net amount by which the actual net injections (injections minus withdrawals) by all *dispatchable generation facilities* and *dispatchable load facilities* is less than the net amount implied by the *IESO's dispatch instructions* to such *facilities*.

4.4.3A Until such time that locational pricing is implemented in the *IESO-administered markets*, the price-insensitive load to be met shall be determined solely on the basis of the net *energy* injections referred to in section 4.4.3.1.

4.4.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:

4.4.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

4.4.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *intertie zone*, given the status of the neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*); and

4.4.4.3 a net *interchange schedule* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid*.

4.4.5 Constraints on the use of the *IESO-controlled grid* shall be determined on the basis of such system *security* requirements as the *IESO* may determine necessary to maintain *reliable* system operations, which requirements shall include, at a minimum, the following:

4.4.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;

4.4.5.2 *security* constraints on identified *facilities*;

4.4.5.3 minimum requirements for each class of *operating reserve*;

4.4.5.4 the *IESO's* commitments to neighbouring *transmission systems* for *operating reserves* and *regulation*;

4.4.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and

4.4.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 4.4.4.3.

4.4.6 The following basic parameters of the *dispatch algorithm* shall be as specified from time to time by the *IESO Board:*

4.4.6.1 the *maximum market clearing price* or *MMCP* that defines the maximum allowable price for *energy*, and the negative of which defines the minimum allowable price for *energy;*

4.4.6.1A the *maximum operating reserve price* or *MORP* that defines the maximum allowable price for any class of *operating reserve*; and

4.4.6.2 the penalty functions for the violation of *dispatch algorithm* constraints.

If the output of the *dispatch algorithm* fails to satisfy *non-dispatchable demand* or the *operating reserve requirements* for any class of *operating reserve* then, subject to section 8.2.2, the penalty functions referred to in section 4.4.6.2 may influence the calculation of *market prices* for *energy* and *operating reserve* in a similar fashion to *offers* and *bids*.

4.4.7 *Interchange schedule data* shall be input as a constant value for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of the *dispatch algorithm* for each *dispatch hour* as determined under section 4.6.

4.5 The Constrained and Unconstrained IESO-Controlled Grids

4.5.1 The *dispatch algorithm* shall be used to determine both operating schedules that reflect the realities of the *integrated power system* and uniform prices within the *IESO control area* that ignore *transmission system* constraints. Thus, the *dispatch* *algorithm* shall be capable of using the following two different models for the *integrated power system:*

4.5.1.1 an *unconstrained IESO-controlled grid model*, which ignores transmission and other *security* constraints on the *IESO-controlled grid* and assumes, in effect, that all *physical services* are provided and consumed at a single, undesignated location *connected* to several isolated *intertie zones* by single transmission lines; and

4.5.1.2 a *constrained IESO-controlled grid model*, which includes a full (but necessarily approximate) mathematical representation of the *integrated power system*, with *interconnections* modelled as single transmission lines to isolated *intertie zones* or as proportionately allocated to *intertie zones*.

4.6 Outputs of the Dispatch Algorithm

4.6.1 The *IESO* shall use the *dispatch algorithm* to determine the quantities and prices summarised in this section 4.6 and detailed in Appendix 7.5.

4.6.2 The *dispatch algorithm* shall be used with the *constrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and to each *dispatch interval*, operating schedules and their associated costs and shadow prices. The principal outputs, for each *dispatch hour* or *dispatch interval*, as the case may be, shall be the following:

4.6.2.1 the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) scheduled to be provided to the *integrated power system* by each *registered facility*;

4.6.2.2 the amounts of *energy* (in MW or MWh/hour) scheduled to be withdrawn from the *integrated power system* by each *registered facility*;

4.6.2.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* scheduled to be provided by *registered facilities*;

4.6.2.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads* and any constraint violations;

4.6.2.5 power flows and *energy* losses on transmission lines;

4.6.2.6 the prices of providing *energy* at each set of transmission nodes identified by the *IESO* for this purpose and, subject to section 4.6.2B, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose.

4.6.2A [Intentionally left blank]

4.6.2B Until the date that is the first day of the fourth calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, the prices of each class of *operating reserve* in each reserve area referred to in section 4.6.2.6 shall not be included as a principal output of the *dispatch algorithm*.

4.6.3 The *dispatch algorithm* shall be used with the *unconstrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and at several times after each *dispatch interval*, *market schedules* and the corresponding uniform prices within the *IESO control area*. The principal outputs of this process are the following:

4.6.3.1 the *market schedule* indicating the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) that would be provided to the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;

4.6.3.2 the amounts of *energy* (in MW or MWh/hour) that would be withdrawn from the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid;*

4.6.3.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* in the *market schedule*;

4.6.3.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads*, and any constraint violations that would occur if transmission were totally unconstrained on the *IESO-controlled grid*; and

4.6.3.5 the prices of providing *energy* and each class of *operating reserve* at any point within the *IESO control area* if transmission were totally unconstrained on the *IESO-controlled grid*. As provided in Chapter 9, the unconstrained prices for each *dispatch interval* shall be used for *settlement* purposes, except for *non-dispatchable loads*, who shall pay a uniform *hourly Ontario energy price* (HOEP) determined as described in section 8.3.1.

4.6.4 The *dispatch algorithm* shall be used with the constrained *IESO-controlled grid model* to determine, prior to each *dispatch hour*, *interchange schedules* and their associated costs. The *interchange schedule* for each *dispatch hour* shall be constant for the *dispatch hour* and used as inputs into the *dispatch algorithm* in accordance with section 4.4.

Appendix C – Appendix 7.5 – The Market Clearing and Pricing Process

1.1 Process Overview and Interpretation

1.1.1 This Appendix sets forth a description of the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, *market schedules* and *market prices*. A detailed mathematical description is also provided in the sections that follow.

1.1.2 [Intentionally left blank]

1.1.3 References to "outputs" in this Appendix refer to data produced by software and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

2. The Dispatch Scheduling and Pricing Process

2.1 Modes of Operation

2.1.1 The *dispatch* scheduling and pricing software may be operated to determine either a *pre-dispatch schedule* or a *real-time schedule* and any associated prices as required by these *market rules*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

2.1.1.1 The *pre-dispatch schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The *pre-dispatch schedule* so produced represents the *energy* forecast to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant* in each *dispatch hour*, and each class of *operating reserve* to be maintained by each *market participant* in each *dispatch hour*;

2.1.1.2 The *real-time schedule* shall represent individual *dispatch intervals*. The *real-time schedule* so produced represents the *energy* to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant*, and the *operating reserve* to be maintained by each *market participant*, in each *dispatch interval*; and

2.1.1.3 Only the *pre-dispatch schedule* shall include daily *energy* limits specified pursuant to section 3.5.7 of this Chapter.

2.1.1.4 The schedules corresponding to *offers* and *bids* located in *intertie zones* adjoining the *IESO control area* shall be fixed for all *dispatch intervals* within a *dispatch hour* in the *real-time schedule* to equal the *interchange schedules* determined for that same *dispatch hour* based on the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*.

2.2 Inputs

2.2.1 The required inputs to the *dispatch* scheduling and pricing process are:

2.2.1.1 *offers* for *energy* submitted by *generators*;

2.2.1.2 *offers* for each class of *operating reserve* submitted by *generators*;

2.2.1.3 self-schedules submitted by self-scheduling generation facilities for energy and the energy price below which each self-scheduling generation facility reasonably expects to reduce the energy output of such self-scheduling generation facility to zero determined in accordance with section 3.4.4A of this Chapter;

2.2.1.4 forecasts of *energy* submitted by *transitional scheduling generators* and intermittent *generators*;

2.2.1.5 *bids* for *energy* submitted by *dispatchable loads*;

2.2.1.6 *offers* for each class of *operating reserve* submitted by *dispatchable loads*;

2.2.1.7 forecasts of *energy* expected to be withdrawn by *non-dispatchable loads*;

2.2.1.8 coefficients of the penalty functions associated with violation of system constraints (generation, *operating reserves* and transmission) that allow relaxation of these constraints in a specified hierarchical order when the solution to the scheduling problem is otherwise infeasible;

2.2.1.9 *generation facility output* and *dispatchable load* levels prevailing at the start of the *dispatch period* calculation;

2.2.1.10 in respect of the *pre-dispatch schedule* only, daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter;

2.2.1.10A in respect of the *real time* constrained *dispatch schedule* only, the start-up and shut-down times for each *generation facility*;

2.2.1.11 the operating characteristics of all *generation facilities* and *dispatchable loads* including, but not limited to ramp-rate limits and *operating reserve* response parameters and for the *real time* constrained *dispatch schedule* only, the *minimum loading point, forbidden regions* and *period of steady operation*;

2.2.1.12 the operating characteristics of the *IESO-controlled grid* including, but not limited to, the physical flow and loss characteristics and flow limits of *transmission facilities*;

2.2.1.13 the requirements for each of *ten-minute operating reserve* that is synchronized to the *IESO-controlled grid*, *ten-minute operating reserve* that is non-synchronized to the *IESO-controlled grid* and *thirty-minute operating reserve*, and the area requirements for *ten-minute operating reserve*;

2.2.1.14 security constraints determined by the *IESO* to be applicable;

2.2.1.14A the outage schedules for transmission facilities;

2.2.1.15 the limits to be applied, where applicable, on *energy bids*, *energy offers, offers* for *operating reserve*, and *dispatch data* as the case may be, to reflect:

a. transmission loading relief constraints;

b. *generation facility outages*;

c. applicable *contracted ancillary services* arranged for use outside of the market clearing mechanism; and for the *real time* constrained *dispatch schedule* only;

d. start-up and shut-down times;

e. *minimum loading point*;

f. *forbidden regions*;

g. *period of steady operation*; and

h. forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*.

2.2.1.16 imports or exports between the *IESO-control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* including but not limited to inadvertent *intertie* flows and simultaneous activation of reserve. These shall be represented as an increase or decrease in *non-dispatchable load*.

2.3 Optimisation Objective

2.3.1 The *dispatch* scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the *bids* and *offers* submitted and applicable constraints on the use of the *IESO-controlled grid*. Marginal cost-based prices shall also be produced and, for such purpose, *offer* prices shall be assumed to represent the actual costs of suppliers and *bid* prices shall be assumed to represent the actual benefits of consumption by *dispatchable load facilities*.

2.3.2 The *dispatch* scheduling and pricing process shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as described in sections 4.3.2 and 4.3.3 of Chapter 7.

2.3.3 In respect of the *real time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall have as its objective function maximizing the weighted sum of the economic gain from trade among *market participants*, as described in section 4.3.2 and 4.3.3 of Chapter 7, for the *dispatch interval* and for advisory intervals within the study period. Critical intervals are those selected from the study period to be used as input to the objective function. The first critical interval is always the *dispatch interval*. The remaining critical intervals are advisory intervals.

2.4 The IESO-Controlled Grid

2.4.1 The *dispatch* scheduling and pricing process shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas*.

2.4.2 The *dispatch* scheduling and pricing process shall utilise a security-constrained optimal power flow with explicit representation of electrical flows on each transmission element.

2.4.3 Limits on transmission flows in either direction of flow shall be explicitly represented.

2.4.4 Security constraints may limit *generation facility* output and *dispatchable load* or any other variable so as to represent the *security limits* applicable to the *IESO-controlled grid*.

2.4.5 Subject to section 2.4.6, the *IESO* shall estimate static transmission losses and model transmission losses using penalty factors. The *IESO* shall adjust *bid* and *offer* prices using the applicable penalty factor. The *IESO* shall notify *market participants* in a timely manner of any changes to the applicable penalty factors.

2.4.6 The *IESO* shall apply a uniform penalty factor to *variable generators* that are *registered market participants*.

2.5 Operating Reserve

2.5.1 The *dispatch* scheduling and pricing process shall simultaneously optimise *energy* and *operating reserve* schedules, respecting the trade-off functions for *energy* and *operating reserve* of each *registered facility*.

2.5.2 *Operating reserve* shall be scheduled to meet all applicable *reliability standards.*

2.5.3 For the real-time *dispatch* schedule and immediately following a *contingency event*, the *operating reserve* requirements shall be reduced while *operating reserves* are restored in accordance with all applicable *reliability standards*.

2.5.4 The *dispatch* scheduling and pricing process shall respect the trade-off function between *energy* and each class of *operating reserve* separately.

2.5.5 The *operating reserve* scheduled for a *generation facility* shall reflect the ability of that *generation facility* to provide *operating reserve* over the *dispatch interval* given its ramping capability.

2.5.6 *Offers* for each class of *operating reserve* in an area shall be used to meet the requirements for that class of *operating reserve* in that area.

2.5.6A *Offers* for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* that are not scheduled to meet that proportion of *ten-minute operating reserve* which is required to be synchronized with the *IESO-controlled grid* may be scheduled to satisfy the remaining portion of *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*.

2.5.7 Offers for *ten-minute operating reserve* –that is synchronized with the *IESO-controlled grid* or for *ten-minute operating reserve* –that is not synchronized with the *IESO-controlled grid* and that are not scheduled to meet the *ten-minute operating reserve* requirement may be scheduled to satisfy the requirements for a *thirty-minute operating reserve*.

2.5.8 The penalty function applicable as the result of a deficiency in any class of *operating reserve* shall be allowed to have an impact on the *energy* and *operating reserve* prices in the same *dispatch period*.

2.6 Contracted Ancillary Service

2.6.1 The *dispatch* scheduling and pricing process shall include constraints specified by the *IESO* to ensure the adequate provision of *contracted ancillary services*.

2.6.2 The *IESO* may apply constraints to the scheduling of *offers* submitted by *generators* and *bids* submitted by *dispatchable loads* which have contracted to provide *contracted ancillary services* so as to ensure that they are scheduled in a manner to meet their obligations under their respective contracted *ancillary service contracts*.

2.7 Constraint Penalty Functions and Violation Variables

2.7.1 The *dispatch* scheduling and pricing process shall include penalty functions and violation variables which will allow it to automatically violate transmission constraints and operational constraints imposed by the *IESO* (but not *bids* or *offers* or the physical limits of the *facilities* of *market participants*) in situations where no solution would otherwise exist.

2.7.2 Penalty functions for the violation of constraints shall be as specified from time to time by the *IESO Board* in accordance with section 4.4.6.2 of Chapter 7.

2.7.3 Different penalty functions may apply for each of the various *transmission* and operating constraints, reflecting the relative flexibility of *transmission* and operating limits.

2.7.4 The use of violation variables shall indicate that a feasible schedule is possible as long as some constraints are relaxed. If relaxation of such constraints is acceptable for purposes of *real-time operations*, such feasible schedule shall be accepted. If relaxation of such constraints is not acceptable for purposes of *real-time operations,* the *dispatch instructions* issued may differ so that an acceptable schedule can be determined.

2.7.5 The penalty functions used by the *IESO* in an acceptable schedule determined under section 2.7.4 shall be allowed to influence *energy* and *operating reserve* prices.

2.8 Tie-Breaking

2.8.1 Except as otherwise noted in section 2.8.5, if two or more *energy offers* have the same *offer* price and interactions with the *operating reserve market* do not create differences in the cost to the market of utilising each *offer*, the schedules from these *offers* shall be prorated based on an adjusted amount of *energy offered* at that *offer price*. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.2 If two or more *energy bids* have the same *bid* price and interactions with the *operating reserve market* do not create differences in the cost to the market as a whole of utilising each *bid*, the schedules from these *bids* shall be prorated based on an adjusted amount of *energy bid* at that *bid* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.3 If two or more *offers* for a given class of *operating reserve* have the same *offer* price and provided that interactions with the *energy* market and markets for other classes of *operating reserve* do not create differences in the cost to the market as a whole of utilising each *offer*, then the schedules from these *offers* shall be prorated based on an adjusted amount of *operating reserve offered* at that *offer* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.4 The *IESO* shall randomly determine a daily *dispatch* order for *variable generators* that are *registered market participants*, and shall regularly update and publish such daily *dispatch* order in accordance with the applicable *market manual*.

2.8.5 For *variable generators* that are *registered market participants*, if two or more *energy offers* have the same *offer* price resulting in no differences in the cost to the *IESO-administered market* of utilising any of the *offers,* the schedules for these *offers* shall be determined utilising the daily dispatch order determined in accordance with section 2.8.4.

2.9 Load Curtailment

2.9.1 If *non-dispatchable load* cannot be satisfied, the *dispatch* scheduling and pricing process shall violate the power balance for the system as a whole, with *energy* prices being calculated in accordance with section 4.4.6 of this Chapter.

2.10 Self-Scheduling Generation

2.10.1 A *self-scheduling generation facility* shall be treated as a resource that will be scheduled when *energy* prices exceed the greater of negative *MMCP* and the price, if any, specified by that *self-scheduling generation facility* in its *dispatch data* pursuant to section 3.4.4A of Chapter 7. Within the software that implements the formulation described in this Appendix, each *self-schedule* shall be represented in the form of an *energy offer* each with a single *price-quantity* pair.

2.11 Inter-temporal Linkages

2.11.1 Except for the *real-time* constrained *dispatch schedule*, the *dispatch* scheduling and pricing process shall solve one *dispatch* period at a time, but shall respect the ramp rate limits applicable to *generation facilities* and *dispatchable load facilities* between *dispatch* periods.

2.11.2 In respect of a *real-time market* scheduling process, the *operating reserve* ramp rates submitted by *market participants* may be increased to levels determined by the *IESO.*

2.11.3 The *real-time* constrained *dispatch schedule* utilizes a two step optimization technique to maximize the weighted sum of the economic gain from trade among *market participants* for a number of critical intervals over a forward looking study period. For each *real time* constrained *dispatch schedule* critical intervals are selected by the *IESO* from the study period based on defined selection criteria. The first critical interval is always the *dispatch interval*, and the remaining critical intervals are advisory intervals. Both the length of the study period and the number of advisory intervals are configurable and may be changed by the *IESO* in the event of significant improvement or degradation of either computer software and hardware performance, the accuracy of the predicted *demand* values or malfunction of the algorithm. Changing the number of critical intervals will affect the number of intervals provided to *market participants* on the *dispatch* advisory reports. The number of critical intervals and the length of the study period will be documented in the applicable *market manuals*.

2.11.4 The *IESO* may switch to a single interval optimization in the event of a malfunction of the multi-interval optimization algorithm.

2.11.5 In respect of the *real-time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall consist of two steps. The first step considers all of the selected critical intervals together to provide an optimal solution. This uses linearized resource characteristics. The second step solves a set of single interval *dispatch* problems to respect the non-linearities that reflect physical characteristics of resources in accordance with section 6.5.

2.12 Outputs

2.12.1 The *dispatch* scheduling and pricing process shall produce the following outputs:

2.12.1.1 the cost to the marketplace as a whole of the solution;

2.12.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

2.12.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

2.12.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

2.12.1.5 the energy output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

2.12.1.6 the level and location of all load curtailment;

2.12.1.7 flows along all transmission lines;

2.12.1.8 losses on the *IESO-controlled grid*, in the aggregate and by transmission line;

2.12.1.9 the locational *energy* prices at each set of nodes identified by the *IESO* for this purpose for each *dispatch* period;

2.12.1.10 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*;

2.12.1.10A the area price of *ten-minute operating reserve*; and

2.12.1.11 penalty function values that are greater than zero.

3. The Market Scheduling and Pricing Process

3.1 Modes of Operation

3.1.1 The market scheduling and pricing software may be operated to determine either a projected *market schedule* or a *market schedule*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

3.1.1.1 the projected *market schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The projected *market schedule* so produced represents the state of the *IESO-controlled grid* at the end of the *dispatch hour*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *pre-dispatch schedule* for the corresponding *dispatch hour*;

3.1.1.2 the *market schedules* shall represent individual *dispatch intervals*. Each schedule so produced represents the state of the *IESO-controlled grid* at the end of a *dispatch interval*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *real-time schedule* for the corresponding *dispatch interval*;

3.1.1.3 the projected *market schedule* shall include daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter; and

3.1.1.4 subject to section 3.1.2, the *market schedule* process shall take, as inputs, the output levels of *generation facilities* and *dispatchable load facilities* from the preceding period of the corresponding *market schedule* and pricing solution.

3.1.2 Section 3.1.1.4 shall not apply if market operations have been suspended or *administrative prices* have been applied pursuant to section 8.4A.2.2 of this Chapter. In such cases, the *generation facility* and *dispatchable load facility* initial condition inputs used to calculate the first *market schedule* determined from the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2 or from the *dispatch interval* referred to in section 8.4A.17.2 of this Chapter 7, as the case may be, shall be the output levels of *generation facilities* and *dispatchable load facilities* from the last *dispatch interval* of the last corresponding *market schedule* and pricing solution solved, with corresponding modifications to the initial ramp rates to reflect the maximum amount of ramping possible during the *dispatch intervals* for which no *market schedules* were produced.

3.2 Inputs to and Form of the Market Scheduling and Pricing Process

3.2.1 The form of and inputs to the market scheduling and pricing process shall differ from the *dispatch* scheduling and pricing process described in section 2 only as follows:

3.2.1.1 all constraints that limit the ability of *energy* to flow from one node to another node within the *IESO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IESO control area* at a single, undesignated location connected to each *intertie zone* only by a single notional *intertie*. Any link between *intertie zones* that lie outside the *IESO control area* shall be removed;

3.2.1.1A all area constraints on *ten-minute operating reserve* shall be removed;

3.2.1.1B the market model shall produce a uniform price for *energy* and for each class of *operating reserve* in the *IESO control area*. The projected *market schedule* shall also produce prices for *energy* and for each class of *operating reserve* in each of the *intertie zones* adjoining the *IESO control area*. No *intertie zone* prices are required to be produced by the *market schedule* as these values are subsequently derived from the uniform Ontario prices produced by the *market schedule* and the projected *market schedule intertie congestion prices*;

3.2.1.2 *security* constraints shall be ignored except for those that impact on *intertie* flows;

3.2.1.2A constraints imposed on *offers* and *bids* that relate to transmission loading relief shall be ignored. Constraints relating to *generation facility outage* schedules and *contracted ancillary services* shall remain;

3.2.1.3 except for flows across *interties*, transmission losses shall not be associated with transmission line flows. Transmission losses other than in respect of flows across *interties* shall be represented as an increase in *non-dispatchable load*;

3.2.1.3A subject to section 3.2.1.3B, the flow across each *intertie* for all *dispatch intervals* within a *dispatch hour* in the *market schedule* shall be equal to the flow on that *intertie* determined for that same *dispatch hour* in the *market schedule* corresponding to the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*;

3.2.1.3B where the limits on flows between *control areas* change in real-time as a result of an unplanned *intertie outage*, it shall be possible to reduce those limits in the *market schedule*;

3.2.1.4 with the exception of *emergency energy* purchases, any imports or exports between the *IESO control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* shall not be represented directly but shall be represented as an increase or a decrease in *non-dispatchable load*. *Emergency energy* purchases shall not be represented as a decrease in *non-dispatchable load* in the *market schedule*;

3.2.1.5 [Intentionally left blank]

3.2.1.6 [Intentionally left blank]

3.2.1.7 [Intentionally left blank]

3.2.1.8 [Intentionally left blank]

3.2.1.9 [Intentionally left blank]

3.2.1.10 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*;

3.2.1.11 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule*; and

3.2.1.12 during any period when the *IESO* undertakes an *emergency* control action as described in the applicable *market manual* that affects market *demand*, the *IESO* shall, as software capabilities permit, adjust market *demand* in the *market schedule* to offset the impact of the *emergency* control action on the market *demand* where such impact can be determined with reasonable certainty.

3.3 Outputs

3.3.1 The market scheduling and pricing process shall produce the following outputs:

3.3.1.1 the cost to the marketplace as a whole of the solution;

3.3.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

3.3.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

3.3.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

3.3.1.5 the output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

3.3.1.6 the uniform Ontario *energy* price. The projected *market schedule* shall also produce *energy* prices for each intertie zone;

3.3.1.7 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*; and

3.3.1.8 [Intentionally left blank]

3.3.1.9 penalty function values that are greater than zero.

3.3.2 As described in section 8.2.2 of this Chapter, the prices produced as part of the output of the market scheduling and pricing process shall not necessarily be the prices that are used for *settlement* purposes.

4. Glossary of Sets, Indices, Variables, and Parameters

4.1 Interpretation

4.1.1 Unless otherwise noted, all variables and parameters shall be non-negative.

4.1.2 [Intentionally left blank]

4.2 Time

4.2.1 Except where explicitly stated otherwise in Appendix 7.5 or elsewhere, the formulation presented in this Appendix represents a single *dispatch period*.

4.3 Fundamental Sets and Indices

4.3.1 Areas and Nodes

4.3.1.1 An area, interpreted in accordance with section 1.2.3 of this Chapter, is represented by an element of the set AREAS and is indexed by a.

4.3.1.2 [Intentionally left blank]

4.3.1.3 [Intentionally left blank]

4.3.1.4 Any *energy offer*, *energy bid* or *offer* for *operating reserve* can be associated with a node belonging to the set NODES. NODES has a subset INTERNALACNODES to represent those nodes in the *IESO control area* and a subset EXTERNALACNODES to represent those nodes in the *intertie zones* adjoining the *IESO control area*. NODES also has subsets INTERTIEZONE, indexed by z, describing all of those nodes within *intertie zone* z.

4.3.2 *Offers*

4.3.2.1 An *offer* is represented by an element of the set OFFERS and is indexed by g.

4.3.2.2 An *offer* has associated with it an area and a node.

4.3.2.3 [Intentionally left blank]

4.3.2.4 [Intentionally left blank]

4.3.2.5 A subset of OFFERS called $\text{OFFERS}_{\text{ENERGYLIMITED}}$ represents the *offers* which have a daily *energy* limit in force in accordance with section 3.5.7 of this Chapter.

4.3.2.6 Each element of g of OFFERS has a set of offer blocks, $\text{GENERATIONOFFERBLOCKS}_g$.

4.3.2.7 $\text{SECURITYGENERATIONGROUP}_v$ is the group of *offers* constrained with security constraint v.

4.3.2.8 Each *energy offer* has associated with it a set of $\text{GENERATIONRAMPUPBLOCKS}_g$ and a set of $\text{GENERATIONRAMPDOWNBLOCKS}_g$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy offer*.

4.3.2.9 The set ENERGYOFFERBOUNDS, which is indexed by g, describes the set of *energy offers* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits, *generation facility outages* as well as limits imposed by *contracted ancillary services* contracts, and forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*. These limits restrict both the *energy* and *operating reserve* output of a *generation facility*.

4.3.3 *Bids*

4.3.3.1 A *bid* is represented by an element of the set BIDS and is indexed by p

4.3.3.2 A *bid* has associated with it an area and a node.

4.3.3.3 [Intentionally left blank]

4.3.3.4 Each element of p of BIDS has a set of load blocks, $\text{PURCHASEBIDBLOCKS}_{p}$.

4.3.3.5 $\text{SECURITYPURCHASEGROUP}_{v}$ is the group of *bids* constrained with security constraint v.

4.3.3.6 Each *energy bid* p has associated with it a set of $\text{PURCHASERAMPUPBLOCKS}_p$ and a set of $\text{PURCHASERAMPDOWNBLOCKS}_p$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy bid*.

4.3.3.7 The set PURCHASEBOUNDS, which is indexed by p, describes the set of *energy bids* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.4 Operating Reserve Offers

4.3.4.1 An *offer* to provide *operating reserve* by either a *generator* or a *dispatchable load* is represented by an element of the set RESERVEOFFERS and is indexed by r. The index elements r(g) and r(p) mean the value of r denoting the *operating reserve offer* associated with *generator* g and *dispatchable load* p, respectively.

4.3.4.2 An *offer* to provide *operating reserve* has associated with it an area and a node.

4.3.4.3 Each element r of RESERVEOFFERS and c of RESERVECLASSES has a set of offer blocks, $\text{RESERVEOFFERBLOCKS}_{r,c,j}$ where j is the index for the blocks.

4.3.4.4 The set RESERVEBOUNDS_c, which is indexed by r, describes the set of *operating reserve offers*, for each *operating reserve* class c, to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.5 [Intentionally left blank]

4.3.5.1 [Intentionally left blank]

4.3.5.2 [Intentionally left blank]

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

4.3.6 Classes of *Operating Reserve*

4.3.6.1 A class of *operating reserve* is represented by an element of the set RESERVECLASSES and is indexed by c.

4.3.6.2 RESERVECLASSES = {RS10,RNS10,R30} where:

a. RS10 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

b. RNS10 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

c. R30 denotes *thirty-minute operating reserve*.

4.3.7 Security Measures

4.3.7.1 A security measure is represented by an element of the set SECURITY and is indexed by v.

4.3.7.2 The *IESO* may establish parameters for these security measures so as to maintain the security and adequacy of the electricity system.

4.3.7.3 [Intentionally left blank]

4.3.7.4 [Intentionally left blank]

4.3.8 Security Classes

4.3.8.1 Security classes represent the different types of security constraints that may be imposed by the *IESO* and are represented by SECURITYCLASSES.

4.3.8.2 SECURITYCLASSES ={GenericMaximum, GenericMinimum}where GenericMaximum and GenericMinimum are generic constraints that can place limits on combinations of *generation facilities* that are *dispatched* by the *IESO*, *dispatchable load* and AC branch flow simultaneously.

4.3.9 Penalty Functions

4.3.9.1 The formulation contains a number of penalty functions that allow certain constraints to be violated to some extent, with a high penalty cost.

4.3.9.2 Penalty functions have five blocks, indexed by j, so that the per unit penalty can be increased for larger violations. The blocks used are:

a. DEFICITGENERATIONBLOCKS;

b. SURPLUSGENERATIONBLOCKS;

c. [Intentionally left blank]

a. (i) [Intentionally left blank]
b. (ii) [Intentionally left blank]
c. (iii) [Intentionally left blank]

c1. DEFICIT10MINRESERVEBLOCKS;

c2. DEFICITSYNCH10MINRESERVEBLOCKS;

c3. DEFICITTOTALRESERVEBLOCKS;

c4. DEFICITAREARESERVEBLOCKS;

c5. SURPLUSAREARESERVEBLOCKS;

c6. DEFICITINTERTIEBLOCKS;

c7. SURPLUSINTERTIEBLOCKS;

c8. DEFICITEXPORT^{MMCP}BLOCKS;

d. For each v in DEFICITSECURITYBLOCKS$_{v;}$ and

e. For each v in SURPLUSSECURITYBLOCKS$_{v.}$

4.4 Derived Sets

4.4.1 There are numerous subsets that can be derived from the fundamental sets described above. A subscripted fundamental set represents all elements of the fundamental set having the attribute represented by the subscript where the subscript is either the unique index identifier or a set of specified elements of another fundamental set.

4.4.2 Examples of derived sets are:

4.4.2.1 RESERVEOFFERS_a, which is the set of all *offers* for *operating reserve* located within *operating reserve* area a; and

4.4.2.2 [Intentionally left blank]

4.4.2.3 $\text{OFFERS}_{\text{INTERNALACNODES}}$, which is the set of all *energy offers* at nodes in the set INTERNALACNODES (*energy offers* made from within the *IESO control area*).

4.4.2.4 [Intentionally left blank]

4.4.2.5 [Intentionally left blank]

4.5 Functions Defined on Sets

4.5.1 For ease of description, the following functions are defined that operate on elements of sets and return either another set or a single element:

4.5.1.1 *g*(.), where the argument could be an *operating reserve offer* r , or a security measure v, gives the *offer* associated with the argument.

4.5.1.2 *p*(.), where the argument could be an *operating reserve offer* r or security measure v, gives the *bid* associated with the argument.

4.5.1.3 [Intentionally left blank]

4.6 Offers and Bids

4.6.1 Parameters

$\text{GenerationBlockMax}_{g,j}$	The MW element of the j^{th} block of the *offer*.
$\text{GenerationOfferPrice}_{g,j}$	The price element of the j^{th} block of the *offer*. The parameter is unbounded.
$\text{PurchaseBlockMax}_{p,j}$	The MW element of the j^{th} block of the *bid*.
$\text{PurchaseBidPrice}_{p,j}$	The price element of the j^{th} block of the *bid*. The parameter is unbounded.
EnergyOfferMax_g	The maximum MW level for *energy* and *operating reserve* associated with *energy offer* g $\in$ **ENERGYOFFERBOUNDS**
EnergyOfferMin_g	The minimum MW *energy* level associated with *energy* offer g $\in$ **ENERGYOFFERBOUNDS**
EnergyBidMax_p	The maximum MW *energy* level associated with *energy bid* p $\in$ **PURCHASEBOUND**
EnergyBidMin_p	The minimum MW *energy* level associated with *energy bid* p $\in$ **PURCHASEBOUND**

4.6.2 Derived Parameters

$GenerationMaximum_g$	The maximum MW *energy* level associated with *energy offer* g∈ **OFFERS**.
$PurchaseMaximum_p$	The maximum MW *energy* level associated with *energy bid* p∈ **BIDS**.
$FixedPurchases$	A representation of the net amount of non-price responsive withdrawal to be supplied from *energy offers* and *energy bids*.
$GenPF_g$	The loss penalty factor for *energy offer* g∈ **OFFERS**.
$PurPF_p$	The loss penalty factor for *energy bid* p∈ **BIDS**.

4.6.3 Variables

$Generation_g$	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy offer* g∈ **OFFERS**.
$GenerationBlock_{gj}$	The MW *energy* scheduled from the j^{th} block of *energy offer* g∈ **OFFERS**.
$Purchase_p$	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy bid* p∈ **BIDS**.
$PurchaseBlock_{pj}$	The MW *energy* scheduled from the j^{th} block of *energy bid* p∈ **BIDS**.

4.7 Power Balance

4.7.1 Parameters [Intentionally left blank]

4.7.2 Derived Parameters [Intentionally left blank]

4.7.3 Variables

LOSS	The MW losses for the entire *IESO-controlled grid*.

4.8 Operating Reserve

4.8.1 [Intentionally left blank]

4.8.2 Parameters

$\text{ReserveOfferPrice}_{r,c,j}$	The price element of block j of *operating reserve* of class c associated with *operating reserve offer* r. The parameter is unbounded.
$\text{ReserveBlockMaximum}_{r,c,j}$	The maximum MW *operating reserve* of class c available from block j of *operating reserve offer* r.
$\text{ReserveLoadingPoint10}_r$	The *operating reserve* loading point for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *ten-minute operating reserve offer*.
$\text{ReserveLoadingPoint30}_r$	The *operating reserve* loading point for *thirty-minute operating reserve* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *thirty-minute operating reserve offer*.
$\text{ReserveRequirement10}$	The amount of *operating reserve* required to meet the *ten-minute operating reserve* requirement of the *IESO control area*.
$\text{ReserveRequirement30}$	The amount of *operating reserve* required to meet the *thirty-minute operating reserve* requirement of the *IESO control area*.
$\text{SynchReserveProportion}$	The fraction of *ten-minute operating reserve* that must be supplied by *operating reserve* that is synchronized to the *IESO-controlled grid*.
ReserveOfferMax_r	The maximum MW level associated with *operating reserve offer* $r \in$ **RESERVEBOUNDS**.
ReserveOfferMin_r	The minimum MW level associated with *operating reserve offers* $r \in$ **RESERVEBOUNDS**.

4.8.3 Derived Parameters

$\text{ReserveMaximum10}_{r}$	The maximum total *ten-minute operating reserve* from *operating reserve offer* r that can be delivered within ten minutes given the ramping rate for *operating reserve*.
$\text{ReserveMaximum30}_{r}$	The maximum total *operating reserve* from *operating reserve offer* r that can be delivered within thirty minutes given the ramping rate for *operating reserve*.

4.8.4 Variables

$\text{Reserve}_{r,c}$	The scheduled *operating reserve* of class c corresponding to *operating reserve offer r*.
$\text{ReserveBlock}_{r,c,j}$	The scheduled *operating reserve* of class c corresponding to block j of *operating reserve offer* r.

4.9 Security

4.9.1 Limits may be imposed on the output of *generation facilities, dispatchable load facilities* and flow on <u>transmission</u> equipment for *security* reasons.

4.9.2 Parameters

$\text{GenericSecurityMinLimit}_{v}$	The lower limit imposed on the combination of *energy offers* and *energy bids* in security constraint *v*∈**SECURITY.** The parameter is unbounded.
$\text{GenericSecurityMaxLimit}_{v}$	The upper limit imposed on the combination of *energy offers* and *energy bids* in security constraint v∈**SECURITY**. The parameter is unbounded.
$\text{SecurityGroupGenerationWeight}_{v,g}$	The weight associated with *energy offer* g∈**SECURITYGENERATIONGROUP**$_{v}$ in security constraint v. The parameter is unbounded.
$\text{SecurityGroupPurchaseWeight}_{v,p}$	The weight associated with *energy bid* p∈**SECURITYPURCHASEGROUP**$_{v}$ in security constraint v. The parameter is unbounded.
$\text{MaxIntertieZoneFlow}_{z}$	The upper limit imposed on the combination of *energy* and *operating reserve* by constraint z∈ **INTERTIEZONES**. The parameter is

	unbounded.
$MinIntertieZoneFlow_z$	The lower limit imposed on the combination of *energy* and *operating reserve* by constraint z∈ **INTERTIEZONES**. The parameter is unbounded.

4.10 Ramping

4.10.1 *Dispatchable load facilities* and *dispatchable generation facilities* have limits on their ability to move from one level of consumption or production to another. Ramping constraints are enforced by constraining the level of consumption or production to be between an upper and a lower limit. These limits are pre-determined, based on starting load and generation levels and *bid* and *offer* ramp rates. These limits are applicable to all *pre-dispatch schedules*, *market schedule* intervals, and to the first *dispatch interval* of each *real-time* constrained *dispatch*.

4.10.1A In the first step, of the *real time* constrained *dispatch schedule,* as described in section 2.11.5, the ramp limits are linearized and respected in the optimization.

4.10.1B In the second step, the ramp limits are determined by pre-processing based on *dispatch* load and generation in the critical intervals that precede and follow the interval under consideration. The solution is bounded by:

a) the prior critical interval solution as calculated by the second step and applicable non-linearized ramp rates; and

b) back calculating from the following critical interval solution as calculated from the first step using the applicable non-linearized ramp rates.

In the event that these two sets of bounds do not intersect then a) governs.

4.10.2 Parameters for the optimisation determined by pre-processing

$\text{GenerationEndMax}_g$	The maximum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
$\text{GenerationEndMin}_g$	The minimum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
$\text{PurchaseEndMax}_\text{p}$	The maximum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.
$\text{PurchaseEndMin}_\text{p}$	The minimum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.

4.10.3 Parameters for Pre-processing

$\text{RampRate}_{g,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j^{th} block of $\text{GENERATIONRAMPUPBLOCK}_g$ for g∈**OFFERS.**
$\text{RampRate}_{g,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j^{th} block of $\text{GENERATIONRAMPDOWNBLOCK}_g$ for g∈**OFFERS**.
$\text{Generation}_g^{Start}$	The MW *energy* level associated with the *energy offer* at the start of a *dispatch period*. This will be the corresponding $Generation_g$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule*. If the schedule from the previous *dispatch period* is not available (non-critical intervals in *the real time* constrained *dispatch schedule*) it will be produced by interpolating the *dispatches* from the critical intervals before and after it.

$\text{OperatingReserveRampRate}_g$	The single *operating reserve* ramp rate in MW per minute associated with g∈**OFFERS**.
$\text{RampRate}_{p,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j[th] block of $\text{PURCHASERAMPUPBLOCK}_p$ p∈**BIDS**
$\text{RampRate}_{p,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j[th] block of $\text{PURCHASERAMPDOWNBLOCK}_p$ for p∈**BIDS**
$\text{Purchase}_p^{Start}$	The MW *energy* level associated with the *energy bid* at the start of a *dispatch period*. This will be the corresponding *Purchase*$_p$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule.*
$\text{OperatingReserveRampRate}_p$	The single *operating reserve* ramp rate in MW per minute associated with p∈**BIDS**.
$\text{GenerationRampBlockMax}_{g,j}$	The MW component of the jth block of the generator ramp up/down block minus the MW component of the (j-1)th block of the generator ramp up/down block.
$\text{PurchaseRampBlockMax}_{p,j}$	The MW component of the jth block of the *dispatchable load* ramp up/down block minus the MW component of the (j-1)th block of the *dispatchable load* ramp up/down block.

4.10.4 Variables Used in Pre-processing

$\text{TimeTrajStart}_g^{Up}$	The time, on the ramp up trajectory for the *energy offer*, associated with the *Generation*$_g$ variable from the previous *dispatch period*.
RampTraj_g^{Up}	The ramp up trajectory for the *energy offer*
$\text{TimeTrajStart}_g^{Down}$	The time, on the ramp down trajectory for the *energy offer*, associated with the *Generation*$_g$ variable from the previous *dispatch period*.
RampTraj_g^{Down}	The ramp down trajectory for the *energy offer*

$\mathrm{TimeTrajStart}_p^{Up}$	The time, on the ramp up trajectory for the *energy bid*, associated with the *Purchase*$_p$ variable from the previous *dispatch period*.
$\mathrm{RampTraj}_p^{Up}$	The ramp up trajectory for the *energy bid*
$\mathrm{TimeTrajStart}_p^{Down}$	The time, on the ramp down trajectory for the *energy bid*, associated with the *Purchase*$_p$ variable from the previous *dispatch period*.
$\mathrm{RampTraj}_p^{Down}$	The ramp down trajectory for the *energy bid*

4.10.5 Parameters Determined by Pre-processing and Multi-Interval Optimization

$\mathrm{GenerationRampBlock}_{g,j}$	The MW *dispatched* from the jth block of the *generation facility* ramp up/down block.
$\mathrm{PurchaseRampBlock}_{p,j}$	The MW *dispatched* from the jth block of the *dispatchable load* ramp up/down block.

4.11 Energy Constrained Generation Units

4.11.1 Parameters for the Optimisation Determined by Pre-processing

$\mathrm{EnergyRemaining}_g$	The amount of *energy* remaining at the beginning of the current *dispatch period* for *energy* constrained *generation facility*, as described in sections 6.6 and 8.3, associated with *energy offer* g.
$\mathrm{Generation}_g^{Previous}$	The amount of *energy* scheduled from *energy offer* g in the preceding dispatch period.

4.11.2 Parameters for Pre-processing

$\mathrm{EnergyOffered}_g$	The total *energy* limit for the *trading day* associated with *energy offer* $g \in$ **OFFERS**.

4.12 Violation Variables

4.12.1 Violation variables have been added to all constraints which might potentially be violated. Most will have a very high cost indicating that the problem has no solution, but some may have lower costs indicating that the constraint can be relaxed to some degree.

4.12.1.1 Parameters

$DeficitGenerationPenalty_j$	The penalty per unit of the *DeficitGenerationBlock*$_j$ variable.
$SurplusGenerationPenalty_j$	The penalty per unit of the *SurplusGenerationBlock*$_j$ variable.
$Deficit10MinReservePenalty_j$	The penalty per unit of the *Deficit10MinReserveBlock*$_j$ variable.
$DeficitSynch10MinReservePenalty_j$	The penalty per unit of the *DeficitSynch10MinReserveBlock*$_j$ variable.
$DeficitTotalReservePenalty_j$	The penalty per unit of the *DeficitTotalReserveBlock*$_j$ variable.
$DeficitSecurityPenalty_{j,v}$	The penalty per unit of the *DeficitSecurityBlock*$_{j,v}$variable.
$SurplusSecurityPenalty_{v,j}$	The penalty per unit of the *SurplusSecurityBlock*$_{v,j}$ variable.
$SurplusIntertiePenalty_{z,j}$	The penalty per unit of the *SurplusIntertieBlock*$_{z.j}$ variable.
$DeficitIntertiePenalty_{z,j}$	The penalty per unit of the *DeficitIntertieBlock*$_{z.j}$ variable.
$Deficit\ Export^{MMCP}Penalty_{z,j}$	The penalty per unit of the *Deficit Export*^{MMCP} *Block*$_{zj}$ variable.

These penalties, which are set by the *IESO Board* as specified in section 4.4.6 of this Chapter, equal a fixed number multiplied by a quadratic function equal to constant1(x^2) + constant2(x) + constant3. The three constants are user-defined for each penalty function while x equals the sum of total fixed demand and transmission losses divided by the total capacity represented by the *energy offers*.

4.12.1.2 Variables

$DeficitGenerationBlock_j$	The amount by which the aggregate of load plus losses exceeds the *energy* generated. The blocks are cleared in order of increasing cost, so the further the power balance equation is violated, the more extreme the penalty per unit.
$SurplusGenerationBlock_j$	The amount by which *energy* generated exceeds the aggregate of load plus losses.
$Deficit10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement exceeds the *ten-minute operating reserve* scheduled.
$DeficitExport^{MMCP}Block_j$	The amount contributed by block j in accounting for the amount by which the exports (bid at MMCP) have been unsatisfied.
$DeficitSynch10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement that is synchronized to the *IESO-controlled grid* exceeds the *ten-minute operating reserve* scheduled.
$DeficitTotalReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the total *operating reserve* requirement exceeds the total *operating reserve* scheduled.
$DeficitSecurityBlock_{v,j}$	The amount of deficit in meeting security constraint v, in violation block j.
$SurplusSecurityBlock_{v,j}$	The amount of surplus in security constraint v, in violation block j.
$SurplusIntertieBlock_{z,j}$	The amount of surplus in *intertie zone* constraint z, in violation block j.
$DeficitIntertieBlock_{z,j}$	The amount of deficit in *intertie zone* constraint z, in violation block j.

$DeficitAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a exceeds the *ten-minute operating reserve* scheduled in area a.
$SurplusAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a is less than the *ten-minute operating reserve* scheduled in area a.

4.13 General Parameters

4.13.1 Parameters

TradingPeriodLength	Being either 60 minutes, in respect of a *pre-dispatch schedule*, or 5 minutes, in respect of a constrained *real-time schedule*, or 15 minutes in respect of a *market schedule*, as the case may be.

5. Objective Function

5.1.1 As well as the market terms that are used in the objective function, violation variables associated with the various constraints also appear in the objective function.

5.1.1.1 The NetBenefit is maximised, where:

$$
\begin{aligned}
NetBenefit = & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurPF_p \times PurchaseBlock_{p,j} \\
& - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times GenerationBlock_{g,j} \\
& - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\
& - ViolationVariables - TieBreaking
\end{aligned}
$$

In respect of the *real time* constrained *dispatch schedule* only, the first step of the optimization process will maximize the weighted sum of the net benefits from trades in the *dispatch interval* and the advisory intervals. The *IESO* will set the weights for the intervals in the *real time* constrained *dispatch* study period to account for reduced accuracy of inputs for future intervals. The *IESO* shall establish the process by which weights assigned to non-critical intervals are allocated to the critical intervals.

$$NetBenefit = \sum_{\{c \in all critical intervals\}} W_c \begin{bmatrix} \sum_{\{j,p | j \in \mathrm{PURCHASEBIDBLOCKS}_p, \text{where } p \in \mathrm{BIDS}\}} \mathrm{PurchaseBidPrice}_{p,j} \times PurPF_P \times PurchaseBlock_{p,j} \\ - \sum_{\{j,g | j \in \mathrm{GENERATION\ OFFERBLOCKS}_g, \text{where } g \in \mathrm{OFFERS}\}} \mathrm{GenerationOfferPrice}_{g,j} \times \mathrm{GenPF_g} \times GenerationBlock_{g,j} \\ - \sum_{\{j,r,c | j \in \mathrm{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \mathrm{RESERVEOFFERS} \text{ and } c \in \mathrm{RESERVECLASSES}\}} \mathrm{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\ - ViolationVariables - TieBreaking \end{bmatrix}$$

Where W_c is the weight assigned to the critical interval c.

5.1.1.2 Wherever the following notation is found:

$$\{\mathrm{j}, x \mid \mathrm{j} \in \mathbf{XBLOCKS}_{\mathbf{x}}, \text{where } x \in \mathbf{GROUP}\}$$

it shall be interpreted as, for each x in the set **GROUP**, take each of the corresponding blocks from **XBLOCKS**.

5.1.1.3 Violation Variable Terms

$$ViolationVariables =$$

$$\sum_{\{j | j \in \mathrm{DEFICITGENERATIONBLOCKS}\}} \mathrm{DeficitGenerationPenalty}_j \times DeficitGenerationBlock_j$$

$$+ \sum_{\{j | j \in \mathrm{SURPLUSGENERATIONBLOCKS}\}} \mathrm{SurplusGenerationPenalty}_j \times SurplusGenerationBlock_j$$

$$+ \sum_{\{j | j \in \mathrm{DEFICIT10MINRESERVEBLOCKS}\}} \mathrm{Deficit10MinReservePenalty}_j \times Deficit10MinReserveBlock_j$$

$$+ \sum_{\{j | j \in \mathrm{DEFICITSYNCH10MINRESERVEBLOCKS}\}} \mathrm{Deficit10MinSynchReservePenalty}_j \times DeficitSynch10MinReserveBlock_j$$

$$+ \sum_{\{j | j \in \mathrm{DEFICITTOTALRESERVEBLOCKS}\}} \mathrm{DeficitTotalReservePenalty}_j \times DeficitTotalReserveBlock_j$$

$$+ \sum_{\{j,a | j \in \mathrm{DEFICITAREARESERVEBLOCKS_A}, \text{ where } a \in AREAS\}} \mathrm{Deficit10MinReservePenalty}_j \times DeficitAreaReserveBlock_{a,j}$$

$$+ \sum_{\{j,a | j \in \mathrm{SURPLUSAREARESERVEBLOCKS_A}, \text{ where } a \in AREAS\}} \mathrm{Surplus10MinReservePenalty}_j \times SurplusAreaReserveBlock_{a,j}$$

$$+ \sum_{\{j,v | j \in \mathrm{DEFICITSECURITYBLOCKS}_v, \text{ where } v \in \mathrm{SECURITYMIN}\}} \mathrm{DeficitSecurityPenalty}_{v,j} \times DeficitSecurityBlock_{v,j}$$

$$+ \sum_{\{j,v | j \in \mathrm{SURPLUSSECURITYBLOCKS}_v, \text{ where } v \in \mathrm{SECURITYMAX}\}} \mathrm{SurplusSecurityPenalty}_{v,j} \times SurplusSecurityBlock_{v,j}$$

$$+ \sum_{\{j,z | j \in \mathrm{SURPLUSINTERTIEBLOCKS}_z, \text{ where } z \in \mathrm{INTERTIEZONES}\}} \mathrm{SurplusIntertiePenalty}_{z,j} \times SurplusIntertieBlock_{z,j}$$

$$+ \sum_{\{j,z | j \in \mathrm{DEFICITINTERTIEBLOCKS}_z, \text{ where } z \in \mathrm{INTERTIEZONES}\}} \mathrm{DeficitIntertiePenalty}_{z,j} \times DeficitIntertieBlock_{z,j}$$

$$+ \sum_{\{j,z | j \in \mathrm{DEFICITEXPORT^{MMCP}\ BLOCKS}_z, \text{ where } z \in \mathrm{INTERTIEZONES}\}} \mathrm{DeficitExport^{MMCP}\,Penalty}_{z,j} \times DeficitExport^{MMCP}Block_{z,j}$$

5.1.1.4 The Tie Breaking Term

$$TieBreaking = \sum_{\{j,p|j\in \text{PURCHASEBIDBLOCKS}_p, \text{where } p\in \text{BIDS}\}} \left\{ \frac{0.0005 \times \left(PurchaseBlock_{p,j}\right)^2}{\text{PurchaseBlockMax}_{p,j}} \right\}$$

$$+ \sum_{\{j,g|j\in \text{GENERATION OFFERBLOCKS}_g, \text{where } g\in \text{OFFERS}\}} \left\{ \frac{0.0005 \times \left(GenerationBlock_{g,j}\right)^2}{\text{GenerationBlockMax}_{g,j}} \right\}$$

$$+ \sum_{\substack{\{j,r,c|j\in \text{RESERVEOFFERBLOCKS}_{r,c}, \\ \text{where } r\in \text{RESERVEOFFERS and } c\in \text{RESERVECLASSES}\}}} \left\{ \frac{0.0005 \times \left(ReserveBlock_{r,c,j}\right)^2}{\text{ReserveBlockMax}_{r,c,j}} \right\}$$

The tie breaking term involves a penalty cost of 0.0005 prorated by the amount scheduled over the maximum amount that could be scheduled from each block. When this cost is multiplied by the amount scheduled from that block, we get a quadratic function that increases as the amount scheduled increases. The penalty cost adders effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the block but by 0.0005 if the entire amount represented by the *bid* or *offer* block is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that, for example, two otherwise tied *energy offer* blocks will be scheduled to the point where their modified costs are identical, effectively achieving a prorated result.

6. Dispatch Constraints

6.1 Offers and Bids

6.1.1

$$GenerationBlock_{g,j} \leq \text{GenerationBlockMax}_{g,j}$$

$$\{j, g \mid j \in \textbf{GENERATION OFFERBLOCKS}_{\mathbf{g}}, \text{where } g \in \textbf{OFFERS}\}$$

6.1.2

$$Generation_{\mathbf{g}} = \sum_{j\in \textbf{GENERATIONOFFERBLOCKS}_{\mathbf{g}}} GenerationBlock_{g,j}$$

$$\{g \in \textbf{OFFERS}\}$$

6.1.3

$$Generation_{g} \geq \text{EnergyOfferMin}_{g}$$

$$\{g \in \textbf{ENERGYOFFERBOUNDS}\}$$

6.1.4

$$Generation_{\mathrm{g}} + \sum_{c \in \mathrm{RESERVECLASSES}} Reserve_{r(g),c} \leq \mathrm{EnergyOfferMax}_{g}$$

$$\{ \mathrm{g} \in \mathbf{ENERGYOFFERBOUNDS} \}$$

6.1.5

$$PurchaseBlock_{\mathrm{p,j}} \leq \mathrm{PurchaseBlockMax}_{\mathrm{p,j}}$$

$$\{ \mathrm{j, p} \mid \mathrm{j} \in \mathbf{PURCHASEBIDBLOCKS_{p}}, \text{where } \mathrm{p} \in \mathbf{PURCHASES} \}$$

6.1.6

$$Purchase_{\mathrm{p}} = \sum_{\mathrm{j} \in \mathbf{PURCHASEBIDBLOCKS_{p}}} PurchaseBlock_{\mathrm{p,j}}$$

$$\{ \mathrm{p} \in \mathbf{PURCHASES} \}$$

6.1.7

$$Purchase_{\mathrm{p}} \geq \mathrm{EnergyBidMin}_{\mathrm{p}}$$

$$\{\mathrm{p} \in \mathbf{PURCHASEBOUNDS}\}$$

6.1.8

$$Purchase_{\mathrm{p}} \leq \mathrm{EnergyBidMax}_{\mathrm{p}}$$

$$\{\mathrm{p} \in \mathbf{PURCHASEBOUNDS}\}$$

All *energy offers* are entered as *offers* to supply a block of *energy* at a minimum price. Similarly, *energy bids* for *dispatchable load* are entered as *bids* to buy a block of *energy* at a maximum price. *Energy offers* must have the price increasing with increasing quantity while *energy bids* must have the price decreasing with increasing quantity.

6.2 Power Balance

6.2.1 The power balance equation states that the total generation must equal the sum of scheduled *energy bids* , withdrawals by *non-dispatchable load* and losses. The sum of withdrawals by *non-dispatchable load* and associated losses are input based on forecasted demand.

6.2.1.1

$$\sum_{\mathrm{g} \in \mathrm{OFFERS}} Generation_{\mathrm{g}} = \sum_{\mathrm{p} \in \mathrm{BIDS}} Purchase_{\mathrm{p}} + \mathrm{FixedPurchases} + LOSS$$
$$- \sum_{\mathrm{j} \in \mathrm{DEFICITGENERATIONBLOCKS}} DeficitGenerationBlock_{\mathrm{j}}$$
$$+ \sum_{\mathrm{j} \in \mathrm{SURPLUSGENERATIONBLOCKS}} SurplusGenerationBlock_{\mathrm{j}}$$

6.2.1.2 [Intentionally left blank]

6.2.1.3 [Intentionally left blank]

6.3 Operating Reserve

6.3.1 [Intentionally left blank]

6.3.2 Operating reserve requirements for the IESO control area are specified for each of ten-minute operating reserve and thirty-minute operating reserve. The ten-minute operating reserve that is required to be synchronized with the IESO-controlled grid is given as a fraction of the ten-minute operating reserve requirement. Since ten-minute operating reserve that is not required for purposes of the ten-minute operating reserve requirement can be used to satisfy the thirty-minute operating reserve requirement, a total operating reserve requirement is defined and is the sum of the ten-minute operating reserve requirement and the thirty-minute operating reserve requirement.

6.3.2A Following a *contingency event*, and subject to section 4.5.10 and 4.5.21 of Chapter 5, the *IESO* shall, over one or more *dispatch intervals*, restore at a constant rate the *operating reserve* requirements to be input into the *dispatch algorithm*. To the extent practicable, the *IESO* shall restore *operating reserve* requirements so as to avoid exceeding the ability to meet those requirements through the *IESO-administered markets*.

6.3.2B *Operating reserve* requirements for areas within the *IESO control area* are specified as lower and upper limits on the amount of *ten-minute operating reserve* to be scheduled in each such area.

6.3.3 [Intentionally left blank]

6.3.3.1

$$ReserveBlock_{r,c,j} \leq \mathrm{ReserveBlockMax}_{r,c,j}$$

$$\{j,r,c \mid j \in \mathbf{RESERVEOFFERBLOCKS}_r, \text{ where } r \in \mathbf{RESERVEOFFERS} \text{ and } c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.2

$$Reserve_{r,c} = \sum_{j \in RESERVEOFFERBLOCKS_{r,c}} ReserveBlock_{r,c,j}$$

$$\{r \in \mathbf{RESERVEOFFERS},\ c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.3 [Intentionally left blank]

6.3.3A

$$Reserve_{\mathrm{r,c}} \geq \mathrm{ReserveOfferMin}_{r,c}$$

$$\{r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES}\}$$

6.3.3B

$$Reserve_{r,c} \leq \text{ReserveOfferMax}_{r,c}$$

$$\{ r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES} \}$$

6.3.3C The *operating reserve* scheduled from *dispatchable loads* cannot exceed the amount of *dispatchable load* scheduled.

$$\sum_{c \in RESERVECLASSES} Reserve_{r(p),c} \leq Purchase_p$$

$$\{ p \in \mathbf{BIDS} \}$$

6.3.4 The *energy* and *operating reserves* scheduled from a *generation facility* must be within the capacity of the *generation facility*.

6.3.4.1

$$Generation_g + \sum_{c \in \text{RESERVECLASSES}} Reserve_{r(g),c} \leq \text{GenerationMaximum}_g$$

$$\{ g \in \mathbf{OFFERS} \}$$

6.3.5 If a *generation facility* is operating at a low level of output, then the amount of *operating reserve* it is capable of providing may be restricted. The Reserve Loading Point corresponds to the minimum level of output at which generators can supply the maximum *operating reserve* within the time required. This maximum *operating reserve* quantity declines to zero as output reduces to zero. The maximum *operating reserve* that can be provided differs for *ten-minute operating reserve* and *thirty-minute operating reserve*, and reflects the differing amount of time available for the *generation facility* to increase its output if the *operating reserve* is activated.

6.3.5.1

$$Reserve_{r(g),RS10} \leq Generation_g \times \frac{\text{ReserveMaximum10}_g}{\text{ReserveLoadingPoint10}_{r(g)}}$$

$$\{g \in \textbf{OFFERS}\}$$

$$Reserve_{r(g),R30} \leq Generation_g \times \frac{\text{ReserveMaximum30}_g}{\text{ReserveLoadingPoint30}_{r(g)}}$$

$$\{g \in \textbf{OFFERS}\}$$

Where:

$\text{ReserveMaximum10}_g = \text{OperatingReserveRampRate}_{r(g)} \times 10$

$\text{ReserveMaximum30}_g = \text{OperatingReserveRampRate}_{r(g)} \times 30$

If either one of $\text{ReserveLoadingPoint10}_{r(g)}$ or $\text{ReserveLoadingPoint30}_{r(g)}$ equals zero then the corresponding equation shall not be included in formulation.

6.3.5.2 [Intentionally left blank]

6.3.5.3 [Intentionally left blank]

6.3.5A The amount of *ten-minute operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within ten minutes. The total *operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within thirty minutes.

6.3.5A.1

$$\sum_{c \in \{\text{RS10},\text{RNS10}\}} Reserve_{r(g),c} \leq \text{Reserve Maximum10}_g$$

$$\{g \in \textbf{OFFERS}\}$$

6.3.5A.2

$$\sum_{c \in \text{RESERVECLASSES}} Reserve_{r(g),c} \leq \text{ReserveMaximum30}_g$$

$$\{g \in \textbf{OFFERS}\}$$

6.3.5B Constraints are imposed in *real-time dispatch* scheduling to recognize that the amount by which a *generation facility's energy* output is scheduled to change during a *dispatch interval* modifies the amount of *operating reserve* that the *generation facility* can reliably provide. For instance, if the *generation facility* ramps up during the *dispatch interval*, then the amount of *ten-minute operating reserve* it can provide within ten minutes of the start of the *dispatch interval* will be reduced.

6.3.5B.1

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \{RS10, RNS10\}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum10}_\text{g}$$

$$\{\text{g} \in \textbf{OFFERS}\}$$

6.3.5B.2

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \text{RESERVECLASSES}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum30}_\text{g}$$

$$\{\text{g} \in \textbf{OFFERS}\}$$

6.3.5C The constraints of 6.3.5B are imposed in *real-time market* scheduling and consistent with the TradingPeriodLength determined by the *IESO* in accordance with section 4.13.1 of Appendix 7.5.

6.3.6 *Operating reserve* is scheduled to meet the *operating reserve* requirements of the *IESO control area*.

6.3.6.1 Ten-minute operating reserve

$$\text{ReserveRequirement10} \leq \sum_{\substack{r \in \text{RESERVEOFFERS},\\ c \in \{RS10, RNS10\}}} Reserve_{r,c}$$

$$+ \sum_{j \in \text{DEFICT10MINRESERVEBLOCKS}} Deficit10MinReserveBlock_j$$

6.3.6.2 Ten-minute operating reserve synchronized with the IESO-controlled grid

$$\mathrm{SynchReserveProportion} \times \mathrm{ReserveRequirement10} \le \sum_{r \in \mathrm{RESERVEOFFERS},\, c \in \{\mathrm{RS10}\}} Reserve_{r,c} + \sum_{j \in \mathrm{DEFICITSYNCH10MINRESERVEBLOCKS}} DeficitSynch10MinReserveBlock_j$$

6.3.6.3 Total operating reserve

$$\mathrm{ReserveRequirement10} + \mathrm{ReserveRequirement30} \le \sum_{r \in \mathrm{RESERVEOFFERS},\, c \in \mathrm{RESERVECLASSES}} Reserve_{r,c} + \sum_{j \in DEFICITTOTALRESERVEBLOCKS} DeficitTotalReserveBlock_j$$

6.3.6.3A Area *operating reserve* requirements

$$\mathrm{MinimumAreaOperatingReserve}_a \le \sum_{r \in RESERVEOFFERS_a,\, c \in \{RS10, RNS10\}} Reserve_{r,c} + \sum_{j \in DEFICITAREARESERVEBLOCKS} DeficitAreaReserve_{j,a}$$

$$\mathrm{MaximumAreaOperatingReserve}_a \ge \sum_{r \in RESERVEOFFERS_a,\, c \in \{RS10, RNS10\}} Reserve_{r,c} - \sum_{j \in SURPLUSAREARESERVEBLOCKS} SurplusAreaReserve_{j,a}$$

$$\{a \in \mathbf{AREAS}\}$$

6.3.6.4 The SynchReserveProportion shall be set in accordance with requirements established by *NERC*.

6.4 Security Constraints

6.4.1 In order to enable the *IESO* to direct the operations of the *IESO-controlled grid* so as to fulfil its obligations under Chapter 5, the *IESO* must define network security constraints. These network security constraints are specified in the form of maximum and minimum constraints on linear combinations of line flows, *energy offers*, and *energy bids*. During the process of solving for schedules and prices, these network security constraints, as well as other transmission constraints represented automatically within the tools, are reduced to generic *security* constraints which impose limits on the weighted sum of the $Generation_g$ and $Purchase_p$ variables, with flows being converted to constants.

6.4.2 [Intentionally left blank]

6.4.3 Generic *security* constraints only appear in the *dispatch* scheduling and pricing process and are expressed as:

6.4.3.1

$$\sum_{n \in \mathrm{SECURITYPURCHASEGROUP}_v} \mathrm{SecurityGroupPurchaseWeight}_{v,p} \times \mathit{Purchase}_p$$
$$+ \sum_{g \in \mathrm{SECURITYGENERATIONGROUP}_v} \mathrm{SecurityGroupGenerationWeight}_{v,g} \times \mathit{Generation}_g$$
$$- \sum_{j \in \mathrm{SURPLUSSECURITYBLOCKS}_v} \mathit{SurplusSecurityBlock}_{j,v} \leq \mathrm{GenericMaxSecurityLimit}_v$$

$$\{v \in \mathbf{SECURITY}_{GenericMaximum}\}$$

6.4.3.2

$$\sum_{p \in \mathrm{SECURITYPURCHASEGROUP}_v} \mathrm{SecurityGroupPurchaseWeight}_{v,p} \times \mathit{Purchase}_p$$
$$+ \sum_{g \in \mathrm{SECURITYGENERATIONGROUP}_v} \mathrm{SecurityGroupGenerationWeight}_{v,g} \times \mathit{Generation}_g$$
$$+ \sum_{j \in \mathrm{DEFICITSECURITYBLOCKS}_v} \mathit{DeficitSecurityBlock}_{v,j} \geq \mathrm{GenericMinSecurityLimit}_v$$

$$\{v \in \mathbf{SECURITY}_{GenericMinimum}\}$$

6.4.4 Constraints separate from the generic security constraints impose limits on the total *energy* flows and *operating reserve* scheduled from *intertie zones* outside the *IESO control area*. These constraints apply to both the *pre-dispatch schedule* and the *market schedule*.

$$\sum_{g \in \mathrm{OFFERS}_z} \mathit{Generation}_g - \sum_{p \in \mathrm{BIDS}_z} \mathit{Purchase}_p + \sum_{r \in \mathrm{RESERVEOFFERS}_z, c \in \mathrm{RESERVECLASSES}} \mathit{Reserve}_{r,c}$$
$$- \sum_{j \in \mathrm{SURPLUSINTERTIEBLOCKS}_z,} \mathit{SurplusInterieBlock}_{z,j} \leq \mathrm{MaxIntertieZoneFlow}_z$$

$$\sum_{g \in \mathrm{OFFERS}_z} \mathit{Generation}_g - \sum_{p \in \mathrm{BIDS}_z} \mathit{Purchase}_p +$$
$$+ \sum_{j \in \mathrm{DEFICITINTERTIEBLOCKS}_z,} \mathit{DeficitInterieBlock}_{z,j} \geq \mathrm{MinIntertieZoneFlow}_z$$

$$\{z \in \mathbf{INTERTIEZONES}\}$$

6.5 Ramping

6.5.1 Any change in the output of a *generation facility* or the consumption by a *dispatchable load facility* is subject to up and down ramp rate limits. These constrain the schedule for these *facilities* at the end of the *dispatch period* to be within a band which is set by pre-processing based on knowledge of the schedule at the start of the *dispatch period* and the ramp rates.

6.5.2 Except for the advisory intervals in the *real time* constrained *dispatch*, ramping constraints are expressed as:

6.5.2.1

$$Generation_g \leq \mathrm{GenerationEndMax}_g \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.2.2

$$Generation_g \geq \mathrm{GenerationEndMin}_g \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.2.3

$$Purchase_p \leq \mathrm{PurchaseEndMax}_p \qquad \{p \in \mathbf{BIDS}\}$$

6.5.2.4

$$Purchase_p \geq \mathrm{PurchaseEndMin}_p \qquad \{p \in \mathbf{BIDS}\}$$

6.5.3 For purposes of sections 6.5.2.1 to 6.5.2.4, $\mathrm{GenerationEndMax}_g$, $\mathrm{GenerationEndMin}_g$, $\mathrm{PurchaseEndMax}_p$ and $\mathrm{PurchaseEndMin}_p$ are determined by pre-processing as described in section 8.2.

6.5.4 The ramping constraints for the advisory intervals in the first step of the multi-interval optimization of the *real time* constrained *dispatch* are linearized and included in the optimization as follows:

6.5.4.1

$$Generation_g = \sum GenerationRampBlock_{g,j} \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.4.2

$$Purchase_p = \sum PurchaseRampBlock_{p,j} \qquad \{p \in BIDS\}$$

6.5.4.3

$$0 \leq GenerationRampBlock_{g,j} \leq GenerationRampBlockMax_{g,j} \qquad \{g \in OFFERS\}$$

6.5.4.4

$$0 \le PurchaseRampBlock_{p,j} \le PurchaseRampBlockMax_{p,j} \quad \{p \in BIDS\}$$

6.5.4.5

$$-RampRate_{g,j}^{Down} \times T_{g,j} \le GeneratorRampBlock\,(i+1th\ \mathrm{int}\ erval)$$

$$-GeneratorRampBlock_{g,j}(ith\ \mathrm{int}\ erval) \le RampRate_{g,j}^{Up} \times T_{g,j}$$

Where $T_{g,j} \ge 0$ and $\sum T_{g,j} \le$ Time Interval; and

$T_{g,j}$ is the time that the generator ramps in the *GeneratorRampBlock*$_{g,j}$; where Time Interval is equal to the length of the *dispatch interval*.

6.5.4.6

$$RampRate_{p,j}^{Down} \times T_{p,j} \le PurchaseRampBlock(i+1th\ \text{int}\ erval)$$
$$- PurchaseRampBlock_{p,j}(ith\ \text{int}\ erval) \le RampRate_{p,j}^{Up} \times T_{p,j}$$

Where $T_{p,j} \ge 0$ and $\sum T_{p,j} \le$ Time Interval; and

$T_{p,j}$ is the time that the purchase ramps in the *PurchaseRampBlock*$_{p,j}$*;* where Time Interval is equal to the length of the *dispatch interval.*

6.6 Energy Constrained Generation Units

6.6.1 Some *generation units*, referred to as "*energy* constrained *generation units*", have a defined amount of *energy* which they are able to generate within the course of a *trading day*. Each *energy* constrained *generation unit* may specify an *energy* limit which will apply over the *trading day*. Where an *energy* limit is specified pursuant to section 3.5.7 of this Chapter, starting with this value a running total, EnergyRemaining, is kept by subtracting the *energy* scheduled in each *dispatch hour* from the quantity of *energy* available at the start of the *dispatch hour*.

6.6.2 Because the model is not inter-temporal, it will not use *energy* at the times at which it is of most value. Instead, it will use *energy* over the first opportunities in which it is economical to do so. Thus, it may use all of the *energy* during the low load early morning period, leaving none left during the higher price periods. It is left to the *generator* to submit *energy offers* for a *generation unit* at appropriate times to maximise the value of the *energy* available.

6.6.3 The following constraint is included only in the *pre-dispatch schedules:*

$$\text{TradingPeriodLength} \times Generation_g \le \text{EnergyRemaining}_g$$

$$\{g \in \mathbf{OFFERS}_{ENERGYLIMITED}\}$$

6.7 Nodal Price Calculation

6.7.1 $$\lambda_n = \lambda_s + (DF_n - 1) * \lambda_s + \sum_k DF_n * a_{nk} * \mu_k$$

where:

λ_n	nodal price at an injection or withdrawal node *n* (i.e., a node connected to a *generation facility* or *load facility*)
λ_s	system marginal cost
DF_n	delivery factor for node *n* (reciprocal of penalty factor)
a_{nk}	sensitivity factor for injection at node *n* on *transmission* line *k*
μ_k	shadow price for *transmission* line *k* constraint

6.7.2 Nodal prices may be decomposed into an *energy* component, a loss component, and a component for all other *transmission* and system constraints (the three terms on the right hand side, respectively.)

7. Market Constraints

7.1 Introduction

7.1.1 The market model removes all of the AC *transmission* lines inside the *IESO control area*, and consolidates the nodes into a single representative node, the ONTARIONODE. The losses associated with the *transmission* lines in the *IESO control area* are consolidated to this node.

7.1.2 The only AC *transmission* lines in the market model are the *interties* with neighbouring *control areas*. Although these *interties* have flow variables in the market model, under current procedures each interface will have its flows constrained to the scheduled quantities for the relevant *dispatch period*, using *security* constraints.

7.2 Offers and Bids

7.2.1 The market constraints for *energy offers* and *energy bids* are identical to the *dispatch* constraints described in section 6.1 with the exception that constraints associated with the sets ENERGYOFFERBOUNDS and PURCHASEBOUNDS shall not be present if those constraints pertain to transmission loading relief.

7.3 Power Balance

7.3.1 The market power balance equations are identical to the *dispatch* power balance equations described in section 6.2, with the following exceptions:

7.3.1.1 subject to section 7.3.2, losses within the *IESO control area* will be added to FixedPurchases;

7.3.1.2 all loss sensitivity parameters (and corresponding penalty functions) for *generators* and *loads* within each *control area* outside the *IESO control grid* will be identical and will reflect the losses on the external area and the relevant *intertie;* and

7.3.1.3 subject to section 7.3.2, the following adjustments, as further defined in section 8.4, shall be made in the *real-time schedule* to reflect deviations between scheduled and actual MW output and load:

ActualPurchaseAdjustment – ActualGenerationAdjustment

7.3.2 Until such time that locational pricing is implemented in the *IESO-administered markets*:

7.3.2.1 the losses referred to in section 7.3.1.1 shall be incorporated in FixedPurchases in the manner described in section 8.4.3 ; and

7.3.2.2 no adjustments shall be made pursuant to section 7.3.1.3.

7.4 Operating Reserve

7.4.1 The market treatment of risk and *operating reserve* is identical to the *dispatch* treatment of these elements as described in section 6.3, with the exception that:

7.4.1.1 constraints on *offers* for *operating reserve* associated with the set RESERVEBOUNDS_c for *operating reserve* class c shall not be present if those constraints pertain to transmission loading relief; and

7.4.1.2 the area *operating reserve* requirements are ignored.

7.5 Security Constraints

7.5.1 The only security constraints to be represented are the limits imposed on the flows of *energy* and on *operating reserve* scheduled from *intertie zones* outside the *IESO control area* as described in section 6.4.4.

7.6 Ramping

7.6.1 The mathematical description of the market constraints for ramping is identical to the mathematical description of the ramping *dispatch* constraints used in the *pre-dispatch* and the *dispatch interval* of the *real time* multi-interval *dispatch*, as described in section 6.5, except for the information and data differences specified in section 6.4 of Chapter 7.

7.7 Energy Constrained Generation Units

7.7.1 This constraint is only included in the *pre-dispatch schedules*. The market *energy* constraints are identical to the *dispatch energy* constraints as described in section 6.6.

8. Parameters and Pre-processing

8.1 Introduction

8.1.1 This section 8 contains calculations that take place before the optimization algorithm. The purpose of these calculations is to convert raw input data into the specific inputs required by the optimisation algorithm.

8.2 Ramping

8.2.1 The pre-processing calculations described in sections 8.2.2 and 8.2.3 are performed for all *energy offers*$\{g \in \mathbf{OFFERS}\}$. The pre-processing calculations described in sections 7.2.4 and 7.2.5 are performed for all *bids* by *dispatchable loads* $\{p \in \mathbf{BIDS}\}$.

8.2.2 The *energy offer* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\mathrm{GenerationEndMax}_g = RampTraj_g^{Up}(TimeTrajStart_g^{Up} + \mathrm{TradingPeriodlength})$$

where

$$Generation_g^{Start} = RampTraj_g^{Up}(TimeTrajStart_p^{Up})$$

8.2.3 The *energy offer* ramp down model is defined by the set of ramp down rates and ramp down blocks. Combined these rates and blocks define the ramp trajectory which gives the maximum decrease of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\mathrm{GenerationEndMin}_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down} + \mathrm{TradingPeriodlength}).$$

where

$$Generation_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down})$$

8.2.4 The *energy bid* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\mathrm{PurchaseEndMax}_p = RampTraj_p^{Up}(TimeTrajStart_p^{Up} + \mathrm{TradingPeriodlength})$$

where

$$Purchase_p^{Start} = RampTraj_p^{Up}(TimeTrajStart_p^{Up})$$

8.2.5 The *energy bid* ramp down model is defined by the set of ramp down rates and ramp down blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum decrease of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\mathrm{PurchaseEndMin}_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down} + \mathrm{TradingPeriodlength}).$$

where

$$Purchase_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down})$$

8.3 Energy Constrained Generation Units

8.3.1

$$\mathrm{EnergyRemaining}_g = \mathrm{EnergyRemaining}_g^{Previous} - \mathrm{Generation}_g^{Previous} \times \mathrm{SchedPeriod}$$

where SchedPeriod is the scheduling period measured in hours, currently 1 hour. If $\mathrm{EnergyRemaining}_g$ ever takes a value of less than zero then it shall be set to zero. If $\mathrm{EnergyRemaining}_g$ is ever lower than a lower bound constraint imposed on *energy offer* g, then as part of the pre-processing process the relevant lower bounds will be reduced accordingly.

8.3.2

$\mathrm{EnergyRemaining}_g = \mathrm{EnergyOffered}_g$ in the first *dispatch period*.

8.4 Actual Dispatch Adjustment

8.4.1 Subject to section 8.4.3, Actual Generation Adjustment shall be:

8.4.1.1 for the ONTARIONODE:

$$\mathrm{ActualGenerationAdjustment}_{\mathbf{ONTARIONODE}} = \sum_{n \in \mathbf{INTERNALNODES}} \sum_{g \in \mathbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\text{Generation}_g^{\text{Actual}}$ is the actual generation for generator g, and $\text{Generation}_g^{\text{Scheduled}}$ is the *dispatch instruction* issued for generator g; and

8.4.1.2 for $n \in$ EXTERNALACNODES:

$$\text{ActualGenerationAdjustment}_n = \sum_{g \in \textbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\text{Generation}_g^{\text{Actual}}$ is the actual generation for generator g, and $\text{Generation}_g^{\text{Scheduled}}$ is the *dispatch instruction* issued for generator g.

8.4.2 Subject to section 8.4.3, Actual Purchase Adjustment shall be:

8.4.2.1 for the ONTARIONODE:

$$\text{ActualPurchaseAdjustment}_{\textbf{ONTARIONODE}} = \sum_{n \in \textbf{INTERNALNODES}} \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p; and

8.4.2.2 for $n \in$ EXTERNALACNODES:

$$\text{ActualPurchaseAdjustment}_n = \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p.

8.4.3 Until such time that locational pricing is implemented in the *IESO-administered markets*, there shall be no actual dispatch adjustment effected pursuant to section 8.4.1 or 8.4.2 and rather than adding the losses within the *IESO control area* to FixedPurchases, FixedPurchases shall be defined to include losses and shall be:

8.4.3.1 the sum of:

a. actual metered generation within the *IESO control area;* and

b. net scheduled flows over all *interties,*

minus

8.4.3.2 the amount of scheduled *dispatchable load* within the *IESO control area*.

RFP

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Power to Ontario.
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Real-Time and Day-ahead Algorithm Reviews

Request for Proposal

Issue 1.0

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

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Important notes:

1. **Conflict of Interest**: Report any real or perceived conflicts of interest in your being involved in this competitive process to IESO's General Counsel for direction. Please provide proof of direction from General Counsel to the Procurement Specialist to retain on file before proceeding with this RFP.
2. **Possible Revenue Sharing Opportunity**: If applicable, is there an opportunity to commercialize this product? If yes, please refer to Rule #5 "Revenue Sharing" in IESO's Intellectual Property Policy IESO_PLCY_0006 to be aware of a requirement to attempt to negotiate a revenue-sharing contract between the IESO and any commercial entity for commercialization of intellectual property.

Table of Contents

1. Introduction

1.1 About the IESO

1 The Independent Electricity System Operator ("IESO") oversees the safe, sustainable and reliable operation of Ontario's power system. The company is also responsible for managing Ontario's wholesale electricity market, through which the supply and demand for electricity are kept in balance and the Hourly Ontario Energy Price is set.

2 Additional information regarding the IESO can be found at: www.ieso.ca

1.2 Objectives of this RFP

3 This RFP is issued by the IESO as an invitation to qualified interested parties to submit Proposals for the provision of the Deliverables, as set out herein.

4 This RFP describes the process by which the IESO intends to select one or more Respondents to enter into a Contract with the IESO for the provision of the Deliverables.

5 The purpose of this RFP is to ensure that the IESO contracts for the Deliverables in an economical, timely and efficient manner through a process that is fair, transparent and accessible to qualified parties and consistent with the provisions set forth in the Provincial Government's Management Board of Cabinet Procurement Directive (April 2011).

1.3 Scope of this RFP

6 This document covers all of the timelines, document format, and legal issues relating to this RFP process.

7 This RFP is not a tender call. This RFP does not commit the IESO in any way to select a Preferred Respondent or to proceed to negotiate or award a Contract.

8 The IESO reserves the right to reject any or all Proposals; to amend or terminate this RFP process; and to retain all Proposals.

9 This RFP is not intended to create, and should not be construed as creating, contractual relations between the IESO and any Respondent.

1.4 Conventions

10 Terms and acronyms used in this document that are *italicized* have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market (the "*market rules*").

11 Each of the rights and powers reserved by the IESO in this RFP may be acted upon by the IESO in its sole and absolute discretion.

1.5 Mandatory and Recommended

12 This RFP specifies numerous format and content-related requirements. Some of them are mandatory and some of them are not mandatory, but recommended and desirable.

13 The words "must", "shall", and "required" mean a mandatory condition that must be met in a substantially unaltered form in order for the Proposal to receive consideration. If a Proposal is not in substantial

compliance with a mandatory requirement of this RFP, the IESO may disqualify the Proposal from this RFP process.

14 The words "should" and "desirable" mean a recommended condition not considered essential, but having a significant degree of importance to the objectives of the RFP and for which preference may be given.

1.6 Definitions

15 In addition to the terms defined elsewhere in this RFP, capitalized terms shall have the meanings given to them below:

- **"Contract"** means a written binding agreement between the IESO and a Preferred Respondent for the provision of the Deliverables, consisting of the documents specified in Section 1 of Appendix D, "Contract Standard A-29-12".
- **"Contractor"** means a Preferred Respondent that enters into a Contract with the IESO.
- **"Closing Date"** means the deadline for submitting a proposal as set out in the Timetable.
- **"Deliverables"** means the goods, services and other deliverables to be provided under Contract, by the Contractor to the IESO, as specified in Section 2.
- **"IESO"** has the meaning specified in Section 1.1.
- **"Intent to Participate Form"** means the form attached hereto at Appendix B, "Intent to Participate Form", as completed and executed by the Respondent.
- **"Form of Offer"** means the form attached hereto at Appendix C.
- **"Preferred Respondent"** means a Respondent, including its successors and assigns, selected by the IESO to enter into negotiations for a Contract.
- **"Proposal"** means the Respondent's formal response to this RFP. A Proposal will be binding on the Respondent's successors and assigns.
- **"Respondent"** means an entity that submits a Proposal or provides an Intent to Participate Form indicating an intention to submit a Proposal.
- **"RFP"** means this Request for Proposal.
- **"RFP Coordinator"** means the IESO's authorized representative, and the Respondent's point of contact, for all purposes relating to this RFP, as specified in Section 3.1.
- **"Timetable"** means the schedule of key procedural dates and times relating to this RFP, as specified in Section 3.8.
- **"Toronto Time"** means Eastern Standard Time or Daylight Saving Time as provided for in the *Time Act* of Ontario.

1.7 Acronyms and Definitions

16 In addition to the terms defined elsewhere in this RFP, capitalized terms shall have the meanings given to them below:

- **"DSO"** means Dispatch Scheduling and Optimization engine which is the software program that implements the dispatch algorithm and is used to determine real-time schedules and prices for the Ontario Electricity Market.
- **"DACE"** means Day Ahead Calculation Engine which is the software program that is part of the day-ahead commitment process and is used to determine day-ahead schedules over a 24-hour period for energy and operating reserves for the Ontario Electricity Market.
- **"DACP"** means Day Ahead Commitment Process which permits the IESO to commit dispatchable generation facilities and economically schedule imports in the day-ahead time frame, in return for a financial guarantee.

- **"Schedule of record"** means the last valid set of results from the day-ahead commitment process used by the IESO for the application of constraints and the calculation of various day-ahead settlement amounts.

– End of Section –

2. Deliverables

2.1 Purpose of this RFP

17 Chapter 7, section 4.2.4 of the market rules requires that:

"Unless otherwise directed by the IESO Board, the IESO shall no less than once every two calendar years, commission and publish the results of an independent review of the operation and application of the dispatch algorithm and the related dispatch processes and procedures. The IESO shall use the results of such review to determine the need or otherwise for improvements in the related dispatch processes and procedures in meeting the objectives of the market rules and/or the mathematical representation of the electricity system or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004."

18 The IESO seeks proposals to perform multi-year (2014, 2016 and 2018) independent reviews of the:

1. Operation and application of the real-time dispatch algorithm and the related dispatch processes and procedures in years 2014, 2016 and 2018; and
2. Operation and application of the day-ahead commitment algorithm and the related processes and procedures in years 2016 and 2018;
3. Respondents may provide proposals for one or both reviews.

2.2 Scope of Work

19 The scope of the real-time review includes assessing compliance with Chapter 7, section 4 (The Dispatch Algorithm) and Appendix 7.5 (The Market Clearing and Pricing Process) of the market rules.

20 The scope the real-time review includes the following:

- The Dispatch Scheduling and Optimization (DSO) engine used with the unconstrained network model for the pre-dispatch and real-time schedules.
- The DSO engine used with the constrained network model for the pre-dispatch and real-time schedules.
- Manual processes and supporting documentation for overriding the DSO outputs.

21 The scope of the day-ahead review includes assessing compliance with Chapter 7, section 5.8 (The Day-Ahead Commitment Pre-Dispatch Scheduling Process) and Appendix 7.5A (The DACP Calculation Engine Process) of the market rules.

22 The scope of the day-ahead review includes the following:

- The Day-Ahead Calculation Engine (DACE) used to determine day-ahead commitments and constrained schedules of the schedule of record.
- Manual processes and supporting documentation for overriding the DACE outputs.

2.3 Out of Scope

23 Providing an external audit opinion on the design and operating effectiveness of controls;

24 Real-time Review: Input data and related applications/systems; all input values to the real-time algorithm are to be assumed as given;

25 Day-ahead Review: Interface software and database which calculates, reads, transfers and stores the data used by the DACE software; and

26 Providing an opinion of the effectiveness of the Information Technology General Controls

2.4 Deliverables

27 The successful Respondent is expected to provide the following deliverables in providing the services for each of the Real-Time and Day-Ahead Algorithm Reviews:

a. Presentation to management and if required to the Audit Committee of the Respondent's approach prior to commencing the review;
b. Information required from the IESO prior to the conduct of field work;
c. Test procedures performed and results;
d. Where applicable and identified, opportunities for improvements in the mathematical representation of the electricity system or the solution procedures which form part of the market clearing logic.
e. Final Report for each Real-Time and Day-Ahead Algorithm Reviews conducted:

   - The report resulting from the reviews will express a conclusion as to whether the operation and application of the respective algorithms and related processes and procedures were applied as intended by the algorithm in accordance with the *market rules*.
   - The report will describe the objective, scope, and approach of the review, including the nature and extent of assurance provided based on the approach and test procedures performed.

f. Oral presentation of each Final Report to the Audit Committee of the IESO Board.
   - **Executive Summary**;
   - **Scope and Approach**;
   - **Summary of Findings and Recommendations, Management Response**; and
   - **Detailed Report** of Control Objectives, Controls, Test Procedures Performed and Test Results and Management Response.

2.5 Project Schedule

28 The contract for the real-time review is for a one (1) year period commencing January 1, 2014, with an option to extend up to two (2) additional one (1) year reviews commencing January 1, 2016 and January 1, 2018 subject to satisfactory service determined by the IESO .

29 The contract for the day-ahead review is for a one (1) year period commencing January 1, 2016, with an option to extend up to one (1) additional review commencing January 1, 2018 subject to satisfactory service determined by the IESO.

30 The Deliverables must be provided in accordance with the following project schedule:

i	Engagement start:	January 1, 2014
ii	Weekly status updates:	Provided to Manager, Internal Audit
iii	Final Report:	No later than September 16, 2014

2.6 Necessary Experience

31 The Respondent must possess the following pre-existing competencies:

- Expert knowledge in electricity dispatch algorithms;
- Expert knowledge of Ontario's two-sequence market design;
- Expert knowledge of other North American electricity markets, including markets that are interconnected with Ontario;
- Working knowledge of Ontario Market Rules and
- Knowledge of economic concepts.

– End of Section –

3. Communicating with the IESO

3.1 RFP Coordinator

32 The IESO has appointed the following person as its RFP Coordinator for all purposes relating to this RFP process:

Rob Rankin
Procurement Specialist
Independent Electricity System Operator
Tel: (905) 855-6265
Fax: (905) 855-6459
E-mail: rob.rankin @ieso.ca and rfp.info@ieso.ca

3.2 General Communications

33 Unless specifically stated otherwise in this RFP, all communications relating to this RFP shall be addressed to the RFP Coordinator in writing by fax or e-mail and shall be executed by an authorized signing officer of the Respondent.

34 No verbal instructions or verbal information provided to the Respondent will be binding on the IESO. The Respondent shall not rely upon any information or instructions relating to this RFP other than those provided in writing by the RFP Coordinator.

3.3 Submitting a Proposal

35 Anyone wishing to submit a Proposal shall do so, in accordance with this RFP, delivered to the IESO's RFP Coordinator prior to the Closing Date as set out in section 3.8.

36 The Proposal must be clearly marked as **"Real-Time and Day-Ahead Algorithm Review RFP Proposal – Private & Confidential".**

37 The Proposal's pricing component (as detailed in Appendix E) must be submitted in a separate attachment, entitled **"Real-Time and Day-Ahead Algorithm Review RFP Proposal – Pricing Component – Private & Confidential".**

38 The Proposal must contain the Respondent's full legal name and return address, and must provide the main contact information of the Respondent.

39 If the Respondent wishes to amend or withdraw its Proposal, it must do so prior to the Closing Date.

3.4 Questions, Clarification and Discrepancies

40 The IESO's written instructions and specifications will be considered clear and complete unless written attention is called to any apparent discrepancies or incompleteness before the RFP Closing Date.

41 The Respondent is advised to examine all of the documents comprising this RFP and is requested to report any errors, omissions or ambiguities. It is the responsibility of the Respondent to seek clarification from the RFP Coordinator on any matter it considers to be unclear and the IESO shall not be responsible for any misunderstanding on the part of the Respondent concerning this RFP.

42 The Respondent may direct questions or seek additional information in writing by e-mail prior to the deadline for submitting questions to the IESO RFP Coordinator.

43 To ensure consistency and quality of information provided to Respondents, all significant interpretations, responses, and supplemental information and instruction provided by the IESO shall be issued in the form of written addenda and provided to all Respondents by fax, e-mail or posting on MERX, without revealing the sources of the inquiries.

44 Notwithstanding the foregoing, the IESO is under no obligation to provide additional information or clarification.

3.5 Due Diligence

45 The Respondent shall be responsible for obtaining its own independent financial, legal, accounting, and technical advice with respect to this RFP and the RFP process and any information included in this RFP and in any addenda, attachments, appendices, data, materials, or documents made available, provided or required pursuant to this RFP. The IESO will not be liable under any circumstances for any information or advice or any errors and omissions that may be contained in this RFP or in the addenda, attachments, appendices, data, materials, or documents made available, disclosed or provided to the Respondent pursuant to this RFP. The IESO makes no representation or warranty, either express or implied, in fact or in law, with respect to the accuracy or completeness of this RFP or such addenda, attachments, appendices, data, materials, or documents. The IESO will not be responsible or liable under any circumstances for any claim, action, cost, loss, damage, or liability whatsoever arising from the Respondent's reliance on or use of this RFP or any other technical or historical addenda, attachments, appendices, data, materials, or documents provided by the IESO.

3.6 Non-Disclosure and Intent to Participate

46 As part of this RFP process, the IESO will require the Respondent to execute the Non-Disclosure Agreement attached hereto as Appendix "A" and return it, by fax or e-mail, to the RFP Coordinator, in accordance with the Timetable.

47 As part of this RFP process, the Respondent shall execute the Intent to Participate Form attached hereto as Appendix "B" and return it, by fax or e-mail, to the RFP Coordinator, in accordance with the Timetable.

3.7 Proposal Presentation

48 The IESO may require the Respondent to give a presentation to the IESO's evaluation team after the Closing Date.

3.8 Timetable for RFP

49 The following Timetable sets out the schedule of key dates and times (Toronto Time) in this RFP process.

RFP release date	February 20, 2013
Respondent's deadline for submitting a Non-Disclosure Agreement	3:00 pm March 6, 2013
Respondent's deadline for submitting questions	3:00 pm March 6, 2013
IESO deadline for issuing addenda	March 13, 2013
Respondent's deadline for submitting Intent to Participate Form	3:00 pm March 18, 2013
RFP Closing Date (Respondent's deadline for submitting a Proposal)	3:00 pm March 21, 2013
Respondent interviews and presentations (as necessary)	Week of April 22, 2013
Expected selection decision	May 1, 2013
Engagement start	January 1, 2014

50 The IESO may amend the Timetable from time to time, upon giving prior notice to all Respondents.

51 If a Respondent fails to submit a Proposal by the Closing Date, then the IESO will disqualify the Respondent from this RFP process.

52 If a Respondent fails to meet any of the other deadlines listed in the table above, then the IESO may disqualify the Respondent from this RFP process.

3.9 RFP Evaluation Process and Criteria

53 In order to determine its responsiveness to the IESO's needs, each Proposal will be checked for the presence or absence of required information in conformance with the requirements of this RFP. A Proposal that does not meet all of the mandatory requirements, including those set out in Section 5, below, may be disqualified by the IESO from further consideration.

54 A Proposal accepted by the IESO as having satisfied the requirements of this RFP will be evaluated against other Proposals and scored based on the following criteria and weighting:

	Evaluation Criteria	Weight
A	**Plan and methodologies utilized to meet the IESO's requirements**: Approach, methodology, and Deliverables (25%); and Project plan and schedule (5%)	30%
B	**Business experience and expertise:** Vendor understanding of IESO's requirements (15%); Vendor expertise and capability (10%); Experience and expertise of proposed team (10%) and Past performance in similar engagements per supplied references (5%)	40%
C	**Price** (total cost to IESO) IESO cost to review exceptions to Contract Standard A-29-12 (5%) Cost of contact – total estimated cost to the IESO over full contract term (25%)	30%

55 The IESO may select a short-list of Respondents to present their Proposals and/or further discuss scope, Deliverables, pricing and related terms and conditions. The IESO may then update the evaluations for short-listed Respondents against the pre-defined evaluation criteria.

56 A Respondent Technical score of less than 50 out of 70 (A+B) will preclude the Respondent from further consideration.

57 The IESO may separate the Deliverables, either by Project, or other basis as the IESO may decide, and select one or more Preferred Respondent(s) to enter into discussions with the IESO for one or more Contract(s) to perform a portion or portions of the Deliverables. If applicable, the IESO will notify, in writing, those Preferred Respondents with whom it intends to enter into concurrent, parallel negotiations.

58 If a Proposal contains false or misleading statements, or provides references which do not support an attribute or condition claimed by the Respondent, the Proposal may be rejected. If, in the opinion of the IESO, such information was intended to mislead the IESO in its evaluation of the Proposal, the Proposal will be rejected.

– End of Section –

4. Proposal Submission Requirements

4.1 Proposal Format

59 The Respondent shall provide the Proposal by email in Microsoft Word format or Adobe pdf.

60 The Proposal shall clearly reference the title of this RFP.

61 The Proposal shall be executed by an authorized signing officer of the Respondent.

62 The Proposal shall set out the Respondent's full legal name and return address, including the contact information for the Respondent's point(s) of contact.

63 The Proposal shall be prepared in separate versions if the Respondent is submitting alternative solutions, and each version should follow the format prescribed in this RFP.

64 The Proposal pricing component must be submitted in a separate attachment.

65 The Proposal shall be in English only.

66 The Proposal shall consist of an "Offer Letter" and a "Technical Proposal". To facilitate ease of evaluation by the IESO's evaluation team, and to ensure each Proposal receives full consideration, the Proposal should be organized in the format specified in this Section 4, using the recommended section titles and sequences.

4.2 Part I: Offer Letter

67 The Respondent must make a number of mandatory commitments and meet a number of mandatory requirements in order to be successful in this RFP process. These mandatory commitments are fully set out in the Form of Offer specified at Appendix C and in Section 5 of this RFP.

4.3 Part II: Technical Proposal

68 The technical portion of the Proposal shall confirm the Respondent's detailed understanding of the RFP and should be presented as follows:

A. **Table of Contents**

B. **Executive Summary:** This section should provide a brief profile of the Respondent and overview of the Proposal. It should summarize the Respondent's qualifications and relevant experience; comment on the Respondent's ability to provide, and the methodology to be used in providing, the Deliverables; and, should specify any intended use of sub-contractors or third parties.

C. **Approach, Methodology, Deliverables and Schedule:** This section should detail:

   i. the approach and methodology for planning, conducting field work and reporting;
   ii. the Respondent's understanding of the required Deliverables, acceptance of the scope of work set out in section 2.2, and the Respondent's technical plan to fulfill them;
   iii. the Respondent's commitment to comply with the IESO's Contract Standard A-29-12 (Appendix D) subject to any proposed changes to that Contract Standard, which must be identified in the Proposal;
   iv. the details of the Respondent's project team and composition; including relevant experience of the proposed project team and professional biographies for each proposed resource, summarizing relevant professional and industry experience, education and certifications; and
   v. the details of the Respondent's plan and schedule of all high-level project activities, referencing the Deliverables and their targeted completion dates. Include estimated IESO resources and effort required and time frame when IESO staff is required to support the review.

D. **References:** The Respondent shall provide a minimum of three (3) references for services that it has provided within the last five (5) years, of similar scope and complexity. At least one (1) supplied reference must be for work conducted in the past twelve 12 months. Each reference shall include a brief description of the services provided, the client's name and the name and telephone number of the client's contact person(s).

E. Other: Any other material, documentation, supporting schedules, exhibits or supplementary information not specifically addressed elsewhere but which is necessary to demonstrate the Respondent's credentials, or to provide a complete understanding of its Proposal, and that is relevant to this RFP should be contained or referenced in this part of the Proposal. The Proposal shall clearly identify all attachments, each of which shall be considered a part of the Proposal. Any assumptions made by the Respondent, which are not explicitly stated elsewhere in its Proposal, should also be described in the response to this section.

F. Respondents Composition: In setting out the details of the Respondent's composition, the Respondent shall specify whether the Respondent is an individual, a sole proprietorship, a corporation, a partnership, a joint venture, an incorporated consortium or a consortium that is a partnership or other legally recognized entity. If the Respondent is a joint venture or a combination of prime and sub-contractors, the Proposal shall clearly: (a) identify the prime contracting member, as the IESO will only contract with one party for the required Deliverables; (b) include a business profile detailing the principal businesses and corporate directions of the individual members; (c) specify the roles and responsibilities of the individual members; (d) identify the financial and other material relationships between the individual members; and (e) describe how the members of the joint venture – or prime/sub-contractor combination – are organized as a team in responding to this RFP.

G. Pricing Proposal: This component of the Proposal should be presented using the form specified "Pricing Proposal Template" at Appendix "E". IESO's preferred approach to award this work is on a fixed price basis. However, Respondents may also offer hourly rates of proposed resources with expected hours to complete this engagement as an alternative.

The IESO reserves the right to award the Contract on either a fixed price or hourly basis. The pricing proposal must be provided in a separate file attachment.

The IESO is subject to the Provincial Government's Management Board of Cabinet, Procurement Directive (April 2011) regarding the engagement of all consulting services and the payment of expenses for consultants. In accordance with the directive, the pricing proposal must, as applicable:

i. acknowledge that pricing is inclusive of all work, except IESO directed travel per vi) below, and associated costs including out of pocket expenses resulting from and during the normal course of a service; and that, unless agreed to in advance, any billings for additional work will not be considered;

ii. outline the process that will be followed for reviewing the pricing should there be a significant increase or decrease in scope (e.g. legislative requirements and/or reliance on internal staff work);

iii. acknowledge that the engagement is considered "local" and the IESO will not be responsible for the Contractor's costs for using "non-local" staff;

iv. detail the Respondent's policy on billing for routine telephone consultations and inquiries;

v. acknowledge that the IESO will not be responsible for the Respondent's expenses incurred in responding to this RFP (accordingly, such costs should not be included in the Proposal) and that all costs and expenses incurred by the Respondent relating to the preparation or presentation of its Proposal or in any way related to this RFP shall be borne by the Respondent. The IESO shall not be liable to pay, or reimburse or compensate, the Respondent for such costs and expenses under any circumstances; and

vi. The IESO will only reimburse expenses for **IESO directed travel** in accordance with the Provincial Government's Travel, Meal and Hospitality Expenses Directive.

– End of Section –

5. Offer Letter

5.1 Form of Offer Letter

69 It is recommended that the Respondent provide its offer letter in the form of the Form of Offer specified at Appendix C. The IESO's Form of Offer contains the Respondent's mandatory commitments and requirements and is simple to follow.

70 Alternatively, the Respondent may use its own form of offer. If the Respondent chooses to submit its own form of offer, it must ensure that it meets all of the mandatory commitments and requirements set out in this section.

5.2 Declaration of Acceptance

71 The Respondent must indicate in its offer letter that it has read and understood the RFP, and has accepted the provisions contained in the RFP. Failure to accept all of the provisions contained in the RFP, subject to the qualification set forth below regarding the Contract Standard, may result in disqualification of the Proposal.

72 The terms set out in this RFP and IESO Contract Standard A-29-12 (Appendix D), governing the supply of services, will be the minimum terms and conditions for the supply of Deliverables by the successful Respondent, if any, in accordance with this RFP. **The Respondent must accept these terms in its offer letter, or propose specific amendments on a point-by-point basis**. A copy of the Respondent's standard terms is not an acceptable response to this requirement. An assumption that accepted contract terms from previous contracts with the IESO will continue to be valid is not an acceptable response to this requirement.

73 The Respondent must clearly declare in its offer letter that, if selected by the IESO as the service provider under a Contract, it will:

i. be able to provide all of the Deliverables in an efficient and professional manner; and

ii. be able to meet the project schedule detailed in this RFP.

5.3 Authorized Representative(s)

74 The Respondent must identify one or more persons as its authorized representative(s) for all matters relating to the Respondent's Proposal and any subsequent Contract between the Respondent and the IESO. The Respondent must confirm that anything said or done by such representative(s) shall be deemed to have been said or done by the Respondent.

5.4 Conflict of Interest

75 The Respondent must indicate in its offer letter whether or not the Respondent has any conflicts of interest (actual or perceived) with respect to this RFP process. Where applicable, the Respondent must declare in its offer letter any situation that may be a conflict of interest.

5.5 References

76 The Respondent must provide consent to the IESO contacting the references listed in its Proposal.

5.6 Security Checks

77 The Respondent shall, if selected by the IESO as the service provider under a Contract, agree to provide documentation if required by the IESO so that the IESO may conduct criminal record searches for all of the Respondent's personnel prior to the commencement of work and shall make its project team members confirm their commitment to abide by the security

and confidentiality obligations of the IESO as set out under the Contract Standard, and as may otherwise be specified by the IESO.

78 If such criminal record searches are required, the final Contract between the IESO and the Respondent will be conditional upon all of Respondent's personnel passing applicable criminal record searches prior to the required engagement start date.

79 All contracted personnel are also required to successfully complete any applicable IESO information security awareness training delivered by the IESO's security team prior to the required engagement start date.

5.7 Disclosure of Disputes

80 The Respondent shall provide a description and disclosure of each claim, lawsuit or other dispute in excess of $100,000 in which the Respondent was involved in the last five (5) years for which any arbitration or court proceeding was commenced.

5.8 Code of Conduct, Intellectual Property and Workplace Violence, Harassment & Discrimination

81 The Respondent shall acknowledge that all of its contracted personnel will be required to review and accept the IESO Code of Conduct (provided as a separate attachment).

82 The Respondent shall acknowledge that it will be required to review and accept the IESO Intellectual Property Policy (provided as a separate attachment).

83 The Respondent shall acknowledge that all of its contracted personnel will be required to review and accept the rules pertaining to workplace violence, harassment & discrimination contained within the IESO Personnel Policy (provided as a separate attachment).

– End of Section –

6. General RFP Terms and Conditions

6.1 IESO's Right to Amend, Supplement, Cancel or Disqualify

84 Notwithstanding anything contained in this document to the contrary, the IESO may at any time, without liability, cost, or penalty to the IESO:

i. amend or supplement this RFP, alter any date specified in this RFP, or cancel this RFP;

ii. elect not to accept any of the Proposals, or to accept only part of a Proposal (and, without limiting the generality of the foregoing, the IESO shall not be obligated to select any given Proposal on the basis of cost, ability to meet the requirements of this RFP, or otherwise);

iii. waive informalities and defects in any Proposal, conduct such investigations of any Respondent that it sees fit with respect to this RFP, and consider any information whatsoever of any Respondent with respect to this RFP;

iv. disqualify any Proposal before the Proposal is fully evaluated if, in the opinion of the IESO, the Proposal contains false or misleading information; or if the Respondent or any of its employees, agents, contractors or representatives contact any member of the IESO other than the RFP Coordinator with respect to this RFP; or if the Respondent has failed to satisfy any of the mandatory requirements of this RFP.

6.2 Withdrawal of Proposals

85 Proposals shall be irrevocable for 180 days from the Closing Date.

6.3 Confidentiality

86 All material, data, information, or any item in any form (including any intellectual property rights derived there under) supplied by or obtained from the IESO, or derived from any data which the Respondent may have acquired in connection with this RFP, the selection and negotiation process under this RFP, both before and after the issuance of the RFP, and the Deliverables:

- is the sole property of the IESO and must be treated as confidential in accordance with the Non-Disclosure Agreement attached hereto as Appendix A. The Non-Disclosure Agreement is applicable with respect to responding to this RFP. The successful Respondent will have an opportunity to negotiate further confidentiality terms with respect to a Contract;
- is not to be used for any purpose other than responding to this RFP and the fulfillment of any subsequent Contract;
- must not be disclosed (unless required by law), including without limitation to anyone at the IESO other than the IESO project team, Chief Executive Officer or Senior Management Team, without prior written authorization from the IESO; and
- must be returned to the IESO upon request.

87 The Proposal and any accompanying documentation submitted by the Respondent prior to the Closing Date shall become the property of the IESO and shall not be returned.

88 The Respondent should identify any information in its Proposal or any accompanying documentation which is supplied in confidence and for which confidentiality is to be maintained by the IESO. The confidentiality of such information will be maintained by the IESO, except as otherwise required by law or by order of a court or tribunal. The IESO may disclose the Proposal, on a confidential basis, to the IESO's advisors retained for the purpose of evaluating or participating in the evaluation of Proposals.

6.4 FIPPA Compliance

90 The *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c.F.31 ("FIPPA"), as amended, applies to information provided to the IESO by a Respondent. In making its Proposal, the Respondent acknowledges that the terms and conditions of any Contract between a successful Respondent and the IESO may be disclosed by the IESO where the IESO is obligated to do so under FIPPA, by an order of a court or tribunal or pursuant to a legal proceeding.

91 By submitting any personal information requested in this RFP, the Respondent agrees to the use of such information as part of the evaluation process, for any audit of this procurement process and for contract management purposes.

6.5 Non Exclusivity

92 By submitting a Proposal and participating in the process as outlined in this RFP, the Respondent expressly agrees that no contract or agreement of any kind is formed under, or arises from, this RFP, prior to the signing of a formal written Contract.

93 Nothing herein is intended nor shall be construed as creating any exclusive arrangement with the successful Respondent. The resulting Contract shall not restrict the IESO from acquiring similar services from other sources.

6.6 Governing Law

94 This RFP and the Contract between the IESO and the successful Respondent shall be governed by and shall be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties hereby irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the Province of Ontario in any suit, action or proceeding arising out of or in connection with this RFP and the Contract between the IESO and the successful Respondent.

– End of Section –

Appendix A: Non-Disclosure Agreement

PROJECT: ***Dispatch Algorithm Review RFP, released February 20, 2013***

NDA WAS SIGNED PRIOR TO RECEIVING THIS RFP DOCUMENT. THIS COPY IS FOR REFERENCE ONLY.

WHEREAS the undersigned company or individual (as applicable, the "Independent Contractor") and the Independent Electricity System Operator ("IESO") wish to exchange information and enter into discussions on a confidential basis with respect to the above referenced project (the "Project");

AND WHEREAS in the course of discussing or evaluating the Project, it may become necessary for the IESO and the Independent Contractor to provide each other with information and/or documentation that each party considers to be of a confidential nature;

NOW THEREFORE in consideration of each party being provided with such Confidential Information (as hereinafter defined), the parties agree:

1. Confidential Information. "Confidential Information" means all data and information, in any form, related to the Project and the business and operations of either party including, without limitation, any and all corporate, financial, economic, legal and customer information, proprietary and trade secrets, technology, accounting records and confidential information of third parties, that has been or will be provided by either party (the "Disclosing Party") to the other party ("the "Receiving Party").

Confidential Information does not include information which: (a) is already in the public domain or becomes available to the public other than through an act or omission of the Receiving Party; (b) must be disclosed pursuant to a legal compulsion; (c) is acquired without obligation of confidence from a source, other than the Disclosing Party, that has a legal right to disclose such information; (d) is previously known by the Receiving Party at the time of disclosure or is independently developed by the Receiving Party without violating the obligations of confidentiality in this agreement; or (e) the Disclosing Party has consented in writing to the Receiving Party's disclosure of such information.

A party claiming any of the foregoing exceptions shall have the burden of proof to establish such applicability.

2. Representatives. "Representatives" means directors, officers, employees, contractors, agents, lawyers, advisors and consultants of a party to this agreement, and includes any Representatives of an affiliate of a party.

3. Restricted Use of Confidential Information. The Receiving Party shall keep the Confidential Information confidential and shall use at least the same degree of care in safeguarding Confidential Information as it uses for its own information of like importance, but in no event less than a reasonable standard of care. Notwithstanding the foregoing, the Receiving Party may disclose the Confidential Information to those of its Representatives who require such information for the purposes of the Project, provided that such Representatives are made aware of and required to comply with the obligations of confidentiality contained in this agreement. The Receiving Party shall comply with other reasonable security measures regarding the Confidential Information requested in writing by the Disclosing Party.

4. Term and Survival. This agreement takes effect on the date it is executed by the Independent Contractor. Notwithstanding the return or destruction of all or any part of the Confidential Information, the terms of this Agreement shall nevertheless remain in full force and effect until seven (7) years from the date hereof.

5. Return or Destruction of Confidential Information. All Confidential Information and any reproductions thereof (both written and electronic) which are in possession of the Receiving Party and its Representatives shall be destroyed or returned to the Disclosing Party immediately following the Disclosing Party's request.

6. Compelled Disclosure. Where the Receiving Party is compelled by law to disclose any Confidential Information, it shall provide the Disclosing Party with prompt written notice and co-operate in good faith with the Disclosing Party in any reasonable, lawful action that the Disclosing Party takes to resist such disclosure.

7. No Representations or Warranties. No representations or warranties, express or implied, are made as to the quality, accuracy, completeness or reliability of either party's Confidential Information. The Disclosing Party shall have no liability whatsoever with respect to the use of or reliance upon the Confidential Information by the Receiving Party.

8. Title. The Disclosing Party retains all title to its Confidential Information and all reproductions thereof. This agreement shall not be construed as granting or conferring any rights to the Receiving Party by license or otherwise in any Confidential

Information (including any patent, patent application, trademark, copyright or trade secret) disclosed under this agreement.

9. Remedies. Any violation or threatened violation of this agreement by the Receiving Party will cause irreparable injury to the Disclosing Party, entitling the Disclosing Party to equitable relief, including injunctive relief and specific performance in addition to all other remedies available at law or equity.

10. Indemnity. The Receiving Party shall be responsible for any disclosure of Confidential Information by any of the Receiving Party's Representatives that is not permitted by this agreement and for any failure by any of the Receiving Party's Representatives to comply fully with the terms of this agreement. The Receiving Party shall defend, indemnify and hold harmless the Disclosing Party from and against all actions, damages, claims, and costs arising out of any breach of this agreement by the Receiving Party or its Representatives.

11. Miscellaneous. This agreement shall not be amended, assigned, nor shall any obligation be waived, except in writing signed by each party. This agreement benefits and binds the parties and their respective successors and permitted assigns. If any part of this agreement is deemed invalid or unenforceable, the balance of this agreement shall remain valid and in full force and effect. This agreement represents the complete agreement between the parties with respect to the subject matter hereof. This agreement is applicable with respect to responding to the abovementioned RFP. The successful Respondent will have an opportunity to negotiate further confidentiality terms with respect to any final written binding agreement with the IESO for the provision of the deliverables for the Project.

12. Execution via Fax or Email. This agreement may be signed in counterparts and delivered by mail, fax or email, each of which shall be deemed an original and all of which shall constitute one agreement.

13. Governing Law. This agreement shall be governed by and shall be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties hereby irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the Province of Ontario in any suit, action or proceeding arising out of or in connection with this agreement.

Agreed to this __ day of _______________, 2012 by,

____
Independent Contractor - Full Legal Name

____
Address

____
Authorized Signature

____
Print Name and Title

- and -

Independent Electricity System Operator
655 Bay St. Suite 410, PO Box 1 Toronto ON M5G 2K4

Procurement Specialist to add his scanned signature on PDF version only

Rob Rankin, Procurement Specialist

Once completed and signed, please return this non-disclosure agreement to:

Rob Rankin, Procurement Specialist

By Fax: (905) 855-6459, or
By Email: rob.rankin@ieso.ca and rfp.info@ieso.ca

- End of Section -

Appendix B: Intent to Participate Form

To: Independent Electricity System Operator (IESO)
Rob Rankin, Procurement Specialist
Tel: (905) 855-6265
Fax: (905) 855-6459
E-mail: rob.rankin@ieso.ca and rfp.info@ieso.ca

Company:____

Address: ____

____

____

City: ____________________ Postal Code: ____________________

Phone: ____________________ Fax Number:____________________

E-mail address:____

We have received a Request for Proposals from the IESO entitled **Dispatch Algorithm Review RFP** and

(**select as applicable**):

- ☐ we intend to submit a Proposal
- ☐ we do not intend to submit a Proposal

Signature: ____

Title: ____________________ Date: ____________________

– **End of Section –**

Appendix C: Form of Offer

Attention: *Rob Rankin*, Procurement Specialist
Independent Electricity System Operator
Tel: (905) 855-6265
Fax: (905) 855-6459
E-mail: rob.rankin@ieso.ca and rfp.info@ieso.ca

FROM: [Name of Respondent] (the "Respondent"): ______________________________

RE : Offer Letter in response to Dispatch Algorithm Review RFP (the "RFP")

This offer letter forms a part of the Proposal that is being submitted in response to the RFP. The Respondent warrants and represents the accuracy and completeness of the information provided below, and understands and accepts each of the conditions and commitments set below.

a) The full legal name of the Respondent is:

b) The head office address, telephone, facsimile number and e-mail address of the Respondent is:

c) The name, address, telephone, facsimile number and e-mail address of each authorized contact person for the Respondent is:

d) The jurisdiction under which the Respondent is governed is:

e) Each individual referred to in Section 1 (c) above is an authorized representative of the Respondent for all matters relating to the Proposal or to any subsequent negotiations to reach a Contract between the Respondent and the IESO. Anything said or done by the authorized representative shall be deemed to have been said or done by the Respondent.

f) The Respondent consents to the disclosure of the Proposal by the IESO, on a confidential basis, to the IESO's consultants retained for the purpose of assisting with this RFP process.

g) The Respondent consents to the IESO performing checks with the references listed in the Proposal.

h) (clause intentionally removed by IESO)

i) The Respondent has read and understands the RFP including, without limitation, Addenda No(s): ______________ (Insert #s or None) and, subject to the qualification set forth below (if any) the Respondent accepts all of the provisions thereof.

j) The Respondent accepts all of the terms and conditions set out in Appendix D of the Proposal, entitled "IESO Contract Standard A-29-12", subject to the Respondent's proposed changes (if any) as specified in the Proposal. The Respondent understands that if it requires that substantial changes be made to the terms and conditions in IESO Contract Standard A-29-12, such requirement may negatively affect the IESO's evaluation of the Respondent's Proposal.

k) The Respondent acknowledges that the *Freedom of Information and Protection of Privacy Act* ("FIPPA") applies to the IESO. The Respondent accepts that the terms and conditions of the Contract between a successful Respondent and the IESO may be disclosed by the IESO where the IESO is obligated to do so under FIPPA, by an order of a court or tribunal or pursuant to a legal proceeding.

l) Insert as applicable:

The Respondent has disclosed all disputes as defined in Section 5.7 Disclosure of Disputes.

m) Insert as applicable:

The Respondent certifies that it does not and will not have any conflict of interest (actual or potential) in submitting the Proposal or fulfilling the obligations as the service provider under the Contract.

Or

The following is a list of situations, each of which is, appears to be or may potentially be a conflict of interest in submitting the Proposal or in fulfilling the obligations as the service provider under the Contract. Other than as set out below, the Respondent certifies that it does not and will not have any conflict of interest (actual or potential) in submitting the Proposal or fulfilling the obligations as the service provider under the Contract.

n) Insert as applicable:

The Respondent has no knowledge, nor the ability to avail itself of, Confidential Information of the IESO in preparing the Proposal (other than Confidential Information which may have been disclosed by the IESO to the Respondent in the normal course of this RFP process) which could result in prejudice to the IESO or an unfair advantage to the Respondent.

Or

The following is a list of situations, each of which is, appears to have knowledge or may potentially have the ability to avail itself of, Confidential Information (other than Confidential Information which may be disclosed by the IESO to the Respondent in the normal course of this RFP process) which could result in prejudice to the IESO or an unfair advantage to the Respondent. Other than as set out below, the Respondent certifies that it does not and will not have any knowledge, nor the ability to avail itself of, Confidential Information (other than Confidential Information which may be disclosed by the IESO to the Respondent in the normal course of this RFP process) which could result in prejudice to the IESO or an unfair advantage to the Respondent.

o) If selected by the IESO as the service provider under a Contract, the Respondent agrees to satisfy all the conditions defined in Section 5.6 Security Checks of the RFP.

p) The Respondent acknowledges and agrees to the terms in the IESO's Code of Conduct, IESO's Intellectual Property Policy and the rules pertaining to workplace violence, harassment & discrimination contained in IESO's Personnel Policy.

q) If selected by the IESO as the service provider under a Contract, the Respondent agrees to satisfy all of the Deliverables in an efficient and professional manner and will meet the project schedule both detailed in the RFP.

[NAME OF RESPONDENT]______________________________

Authorized Signature: ______________________________

Name and Title: ______________________________

Date: ______________________________

– End of Section –

Appendix D: IESO Contract Standard A-29-12

ieso
Power to Ontario.
On Demand.

Class	Number	Date
A	29	12

CONTRACT STANDARD

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

STANDARD COMMERCIAL CONDITIONS FOR CONTRACT SERVICES

Issued November 2012

CONTENTS

1. Contract Documents and Order of Precedence

The contract will consist of (1) the purchase order; (2) these standard commercial conditions; (3) IESO's Request for Proposal; and (4) the Contractor's proposal (collectively, the "Contract"). These documents, and portions thereof, will take precedence in the order in which they are named.

There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in the Contract. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into the Contract, or any amendment or supplement thereto, by any party to the Contract or its directors, officers, employees or agents, to any other party to the Contract or its directors, officers, employees or agents, except to the extent that the same has been reduced to writing and included as a term of the Contract, and none of the parties to the Contract has been induced to enter into the Contract or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact.

2. Governing Law

This Contract shall be governed by and shall be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The parties hereby irrevocably and unconditionally attorn to the exclusive jurisdiction of the courts of the Province of Ontario in any suit, action or proceeding arising out of or in connection with this Contract.

3. Laws, Regulations and Codes

The Contractor will comply with all federal, provincial and municipal statutes, regulations, bylaws, standards and codes which are applicable to the performance of the Contractor's work for the IESO.

The Contractor will also comply with the IESO's Code of Conduct and the rules pertaining to Workplace Violence, Harassment & Discrimination contained in IESO's Personnel Policy, copies of which will be provided to the Contractor.

4. IESO Representative

IESO will inform the Contractor as to the identity of its authorized representative, to whom all correspondence, reports and documents will be addressed. No acceptance, instruction, approval or statement by IESO's authorized representative or by any other representative of IESO will relieve the Contractor from responsibility for proper performance of the work.

5. Independent Contractor Status and Staff

The Contract is a contract for the performance of a service and the Contractor is engaged under the Contract as an independent contractor for that sole purpose. Neither the Contractor nor any of the Contractor's personnel is engaged by the Contract as an employee, servant or agent of the IESO.

Neither party will have the authority to bind the other or to assume or create any obligation or responsibility expressed or implied on the other's part, or in its name, nor will it represent to anyone that it has such power or authority, except as expressly provided in the Contract.

Prior to commencing the work, the Contractor will appoint a manager or professional as Project Manager who will be responsible for the administration and co-ordination of all phases of the work. Contractor's staff shall have the knowledge, abilities, experience and qualifications required for the work and will perform their tasks in a professional manner. Changes to the Contractor's staff will require IESO approval, except in the case where such replacement is as a result of illness or termination of such personnel, in which case the Contractor may remove members of its staff, provided however that IESO may request that it approve, acting reasonably, any replacement. IESO may request, at its discretion, that the dedicated project individual(s) be changed and the Contractor will accommodate such requests.

6. Security Checks

The Contractor shall provide documentation required by IESO so that IESO may conduct security checks for Contractor personnel prior to the commencement of work. Security checks shall include, but may not necessarily be limited to, Canadian Security Intelligence Service searches and Criminal Record searches. The acceptance of the Contract by IESO is conditional upon the IESO being satisfied that Contractor personnel do not pose a security threat to IESO.

7. Assignment or Subletting

This agreement shall not be amended, assigned, sublet, nor shall any obligation be waived, except in writing signed by each party. This agreement benefits and binds the parties and their respective successors.

8. Non-Resident Contractors

The Contractor is responsible for applying to Immigration Canada for admission of personnel into Canada and for obtaining work permits where required. The Contractor will be required to obtain customs clearance and pay duties and taxes where applicable, for goods or tools used in the performance of the work or imported into Canada. Assistance with clearance of goods will be provided by IESO if requested. The Contractor shall pay all applicable taxes on goods and tools notwithstanding that such goods or tools may be duty free, such as those originating in a NAFTA country.

9. Withholding Tax

Certain amounts paid or credited to non-residents of Canada are subject to income tax withholding in accordance with rates and conditions set forth in the Income Tax Act and tax treaties. This tax is remitted to the Canada Revenue Agency. Contractor may apply to the Canada Revenue Agency for a waiver before commencement of the work in Canada to avoid this withholding.

For U.S. contractors, a 15% withholding tax is required on the gross amount payable for services rendered in Canada (i.e., consulting fees, maintenance fees) and 10% withholding tax is required on rentals, royalties and similar payments (including payments for the rights to use computer software).

10. IESO Owned Equipment

Equipment authorized by IESO for purchase by the Contractor or supplied to the Contractor by IESO, will be used solely in the performance of the work unless prior written approval is obtained from IESO. Title to such equipment will remain with IESO. When in the Contractor's possession, it will ensure the equipment will be clearly identified as property of IESO. The Contractor will be responsible for safeguarding such equipment while in its custody and control, maintaining a system of inventory control acceptable to IESO, acting reasonably. IESO will have reasonable access to the premises of the Contractor for the purpose of verifying records and auditing inventories of such equipment.

Following completion of the work or termination of the Contract, the Contractor will, unless otherwise directed by IESO, make all such equipment immediately available for pick up by IESO. The Contractor will be liable for the repair or replacement of all IESO owned equipment which becomes damaged or lost while in the custody or control of the Contractor.

11. Terms of Payment

If established in the Contractor's proposal and referenced in the purchase order, gross, fixed hourly rates may be established for specific personnel or for classes of personnel. Such rates and any proposed increases will be subject to audit as set forth below only for consistency of application of the Contractor's cost factors. Such rates will be subject to adjustment annually for increases in cost factors.

If fixed rates are not established in the purchase order, the Contractor will indicate in advance the hourly rate to be charged for the Contractor personnel engaged in the work. Unless otherwise stipulated, the hourly rate will be broken down in the Contractor's proposal and calculated based on:

(a) the payroll cost of that hour for the particular person involved; plus
(b) a fixed percentage markup on said payroll cost, the percentage being that specified in the Contractor's proposal.

Payroll cost will mean normal salary or wages plus a payroll burden percentage of such salary or wages (as specified in the Contractor's proposal) which represents a provision for statutory holidays, vacation, sick time, unemployment insurance, hospitalization and medical insurance, group life insurance, workers' compensation, and pension plan (tax equalization payments, bonuses and profit-sharing plans will not be included in payroll cost and are not compensable under the Contract). The hourly rate used will be based on the number of regular working hours in 260 working days. Hours charged will be calculated to the nearest hour.

The payroll burden percentage may be revised annually as necessary to reflect changes in statutory and other allowances. IESO will, at its cost, have the right to verify the established rate and revisions thereto.

The fixed percentage mark-up specified in (b) above will be deemed to compensate the Contractor for all corporate, executive and management expenses, general administration expenses, including the services of a project administrator (unless otherwise specified), accounting, employee relations, clerical staff, secretarial support, normal stationery and office supplied, local telephone, rent, utilities and taxes, depreciation and Contractor's fee.

The Contractor's personnel designated as manager or above, including Project Manager, will not be charged to the work unless explicitly contemplated in the Contractor's proposal and they are engaged in making a direct technical contribution thereto or unless otherwise specified. Any effort which contemplates such charges not set out in the Contractor's proposal will require IESO's prior written authorization.

The use of overtime hours on the work will be subject to IESO's prior written approval. Overtime hours will be compensated at straight time hourly rates. If overtime use becomes extensive, IESO will be entitled to a reasonable adjustment in overhead rates to take the increase in billable hours into account.

The services of other contractors will not be employed without the prior written approval of IESO. In such case, the Contractor will be reimbursed, without mark-up, at the per diem rate charged by the other contractor(s).

IESO will not reimburse the Contractor for expenses or administrative charges. Accordingly, these expenses should be included as part of the rates.

12. Invoicing

Charges for services rendered and reimbursable expenses incurred may be submitted monthly unless otherwise specified. Invoices will be in such detail and format as specified by IESO. Payment of acceptable invoices will be made 30 days after receipt thereof. If at any time during the performance of the work there are deficiencies in the work, including non-delivery of an acceptable final report, IESO will have the right to withhold from any invoice an amount that, in IESO's reasonable opinion, takes into account the deficiencies. Any amount withheld will be paid 30 days after receipt of invoice submitted after IESO's approval of the correction of deficiencies.

13. Taxes

All applicable taxes shall be shown separately on all invoices. When submitting an invoice for a pre-approved special expense, the Contractor shall show the expense and tax components as separate line items.

14. Health and Safety

If the work includes field work, the Contractor will comply with all relevant safety rules and regulations, including, without limiting the generality of the foregoing, those established by IESO.

In order to ensure a healthy workplace and address the health hazard posed by the use of scented products in our workplaces, all IESO workplaces have been designated as fragrance free. The Contractor is required to ensure that its personnel who may be at an IESO workplace are made aware of this policy. Non-compliance will result in denial of access for the individual to IESO workplaces or, if the individual has already entered before the fragrance is detected, then the individual will be directed to leave the IESO workplace immediately. No allowances will be made to the Contractor's obligation to complete the work in accordance with the schedule in the Contract because of such denial of access or direction to leave.

The Contractor will not use electronic devices when driving on IESO-related business or activities even if the electronic device has "hands-free" capability. The Contractor will also not use electronic devices at any time while driving to make, take or view and IESO-business-related call, message, text or email, even if the electronic device has "hands-free" capability.

15. Inspection and Warranty

IESO's authorized representative will have the right to inspect the work at all times and may reject any part thereof which is found to be not in accordance with specifications and statements set out in the Contract or otherwise required by law. Any of the work so rejected will be promptly redone by the Contractor at no additional cost to IESO. This will include, but not be limited to, all drawings and data prepared by the Contractor under the Contract which are found, within a period of one year from date of transmittal to IESO, to be incomplete or inaccurate due to a failure to comply with said specifications and standards.

16. Progress Reports

Unless otherwise agreed in the Contract, the Contractor will forward to IESO on or before the 20th day of each month, a progress report in such form and detail as may reasonably be requested by IESO, showing the progress of the work to the end of the preceding month. Such report will also include a summary of the costs to date, estimated cost to completion of the work, and an explanation of any variance from the original estimate. The Contractor will notify IESO immediately upon having expended or committed 80% of the authorized funds.

17. Completion of the Work

The Contractor will complete the work in accordance with the schedule set forth in the Contract and, if necessary, will increase the level of effort/resources necessary to ensure the schedule is maintained. Any price or funding limitations will not be exceeded without IESO's written authorization, notwithstanding any extra efforts required to maintain schedule.

18. Termination

IESO may terminate the work or any portion of the work under the Contract for any reason upon 30 days written notice to the Contractor. Unless otherwise agreed between the Contractor and IESO, upon termination IESO will be obligated to pay the Contractor only for work effort expended and expenses incurred prior to the expiry of the notice period. The Contractor will not undertake any forward commitment after receipt of notice of termination. Either party may terminate the Contract in the event that the other party materially breaches the Contract and such breach is not cured to the reasonable satisfaction of the non-breaching party within 15 days of written notice of such breach.

19. Proprietary Rights; Confidentiality

Both parties will retain all rights to methodology, knowledge, and data brought to the work and used therein. No rights to proprietary interests existing prior to the start of the work are passed hereunder other than rights to use same as provided for below. The Contractor will not knowingly incorporate into the work any data, software or hardware the use of which by IESO violates the proprietary rights of third parties.

All title and beneficial ownership interests to all intellectual property of any form conceived, designed, written, produced, developed or reduced to practice in the course of the work will vest in and remain with IESO. The Contractor waives all moral rights that it has, and shall cause its employees to waive any moral rights they may have, in the work. The Contractor will not do any act which may compromise or diminish IESO's interests as aforesaid.

The Contractor grants to IESO a non-exclusive paid up license to use any data and other proprietary items incorporated into the work by the Contractor hereunder. The Contractor may, by prior written notice and written acknowledgment by IESO's representative, reserve the right to incorporate into the work data or other proprietary property for the use of which the Contractor wishes to charge a fee. If said notice and acknowledgment are not executed prior to the incorporation, the Contractor will be deemed to have waived any such fee. IESO will have the right to exploit such data and property and to license same to third parties provided that such licenses contain reasonable reservations of proprietary rights in favor of the Contractor (which may be included in a general reservation, but will contain the same order of legal protection as the Contractor uses when distributing such data or property to third parties) or provided the use of same does not reveal information proprietary to the Contractor.

Except as required in the performance of the work or as authorized in writing by the owner, each party will keep confidential all proprietary information of the other, including, without limitation, all unpublished business and technical information, papers, or records, however produced. Notwithstanding, the Receiving Party may disclose the scope of work, price of the Contract, and total dollars to one or more unions that represent certain IESO employees as may be required under the applicable collective agreement, provided that such union(s) are made aware of the obligations of confidentiality contained in the Contract. These obligations of confidentiality will survive completion and/or termination of the Contract and will apply for a period of five years from the date of the last invoice submitted by the Contractor hereunder.

20. Compliance with Privacy Laws

In this section, "Personal Information" means any information about an identifiable individual, which before or after the date of the Contract, is exchanged, disclosed, transferred, stored, warehoused, accessed, processed, handled or in any way made available to the Contractor. "Privacy Laws" includes the *Personal Information Protection and Electronic Documents Act* (Canada), *Freedom of Information and Protection of Privacy* (Ontario), and the provisions of any other applicable municipal, provincial or federal or other laws, regulations, decisions, orders, judgments and rulings or regulatory requirements applicable to either party to our agreement from time to time that address the collection, use, transfer or disclosure of Personal Information.

The Contractor agrees to comply with all Privacy Laws applicable to either it or IESO in relation to Personal Information and shall refrain from taking any action that could cause IESO to be in non-compliance with any such Privacy Laws. The Contractor represents that it has named a person (or persons) responsible for ensuring compliance with the obligations of this section . The Contractor agrees to reasonably cooperate with IESO in connection with any access requests for Personal Information as provided for in the Privacy Laws. The Contractor agrees to amend Personal Information as required by the Privacy Laws, only upon receiving instructions to do so from IESO, its personnel or any other individual to whom the Personal Information relates. The Contractor agrees, within 10 business days, to return to IESO or destroy all Personal Information which is no longer necessary to fulfill the purpose(s) for which it was made available, unless otherwise instructed by IESO or required by law.

21. Accounts and Right to Audit

The Contractor will keep proper accounts and records of the work in form and detail satisfactory to IESO. Such accounts and records, including invoices, receipts, time cards and vouchers will at all reasonable times be open to audit, inspection and copying by IESO. Accounts and records will be preserved and kept available for audit until the expiration of two years from the date of completion or termination of the work.

22. Limitation of Liability

Each party's liability under the Contract will be limited to the greater of: (a) the total amount of fees paid or payable by IESO to the Contractor under the Contract; and (b) the total amount of professional errors and omissions insurance coverage the Contractor has in place at the commencement of the work, or which the Contractor obtains during the course of the work and toward the cost of which IESO directly or indirectly (i.e., through payment of overhead markups) contributes.

23. Force Majeure

If the performance of the Contract, or any obligations thereunder, is prevented, restricted, or interfered with by reason of: fire, flood, earthquake, explosion, or other casualty or accident or act of God; strikes or labour disputes; inability to procure or obtain delivery of parts, supplies, power or software from suppliers; failure, delay, interruption or other adverse impact caused by telecommunications carriers, internet service providers, and other intermediaries; war or other violence; any law, order proclamation, regulation, ordinance, demand or requirement of any governmental authority; or any other act or condition whatsoever beyond the reasonable control of the affected party (a "Force Majeure"), the party so affected, upon giving prompt notice to the other party, will be excused from such performance to the extent of such prevention, restriction or interference; provided, however, that the party so affected will take all reasonable steps to avoid or remove such Force Majeure and will resume performance hereunder with dispatch whenever such causes are removed.

24. Severability

If any provisions of the Contract will for any reason be held illegal or unenforceable, such provision will be deemed separable from the remaining provisions of the Contract and will in no way affect or impair the validity or the enforceability of the remaining provisions of the Contract.

– End of Section –

Appendix E: Pricing Proposal Template

IESO's preferred approach to award this Contract is on a fixed price basis. However, Respondents may offer hourly rates of proposed resources with expected hours to complete this engagement as an alternative. The IESO reserves the right to award the Contract on either basis.

Note: The IESO will not reimburse the successful Respondent for any expenses or administrative charges, except as noted in Section 4.3 G. Accordingly, these expenses should be included as part of the rates.

See attached Excel template – titled "Attachment No 01".

– End of Section –

– End of Document –

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BOMA INTERROGATORY 22

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p34***

Please provide a breakdown of the number of IESO personnel spending 100% of their time; between 50% and 100% of their time; between 25% to 50% of their time, and less than 25% of their time - creating, negotiating, renegotiating, or managing, procurement contracts with generators.

RESPONSE

As of August 2017, there were approximately 43 staff who are engaged exclusively in the contract management function within the Market & Resource Development business unit. There are a further 7 staff exclusively engaged in the generation procurement function, which includes the creating, negotiating and administering functions of the generation procurement process that takes place before contracts are in place.

As the Elenchus report outlines, the contract management function is not entirely carried out by the groups above, as their work is supported by other groups within the IESO such as legal, who are not exclusively dedicated to the generation contract management function. The IESO does not track staff effort at a functional level.

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BOMA INTERROGATORY 23

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p36***

(a) Please confirm that the IESO has substantial influence over the reduction of transmission losses (Hydro One Transmission, in its recent rates case, said it was IESO, not Hydro One, that has the most responsibility over losses), and that it would need a directive for the IESO to take steps to reduce transmission losses. How, in IESO's view, is accountability for loss reduction control shared by IESO and Hydro One?

(b) Do any of the AESO, or the US RTO/ISOs have programs, either alone, or in conjunction with the transmitters which they supervise, to reduce system losses? Please provide details and results achieved.

(c) Please provide copies of any studies that IESO has made of transmission losses or that AESO or the IESO's US counterparts have made of such losses in the last few years. What is best practice among the IESO's US counterparts and AESO with respect to taking steps to reduce transmission losses on those transmission facilities that they oversee?

(d) Please provide IESO's definition of transmission losses, and how they are traditionally measured, and what figure is currently used by the IESO in making calculations that require an assumption about the amount of transmission losses. Which are the major IESO functions that require such calculations?

(e) Please provide a copy of the "Operating Agreement" between the IESO and Hydro One Transmission. Does the Agreement deal with the issue of responsibility for reducing transmission losses?

(f) Which amounts for losses are included in the AQEW and SQEW, is calculating domestic and export usage fees, respectively?

(g) Please confirm that end use customers ultimately pay for the losses in their rates. What is the forecast amount and dollar value (show calculation of dollar value) of losses for 2017, 2018? What step is the IESO taking, or plans to take, to try to lower the transmission losses?

RESPONSE

a) Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01.

b) Please refer to the responses to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01 and ED Interrogatory 9 at Exhibit I, Tab 5.1, Schedule 4.09.

c) Please refer to the responses to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01 and ED Interrogatory 9 at Exhibit I, Tab 5.1, Schedule 4.09.

d) Please refer to the responses to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03 and ED Interrogatory 7 at Exhibit I, Tab 5.1, Schedule 4.07.

e) The IESO believes that the Operating Agreement between the IESO and Hydro One is out of scope of the current proceeding. In an effort to be of further assistance to parties, the IESO provides the following context. The agreement is consistent with the IESO's legislative objects and with the Market Rules and manuals. It requires the IESO to balance many complex and sometimes competing priorities in order to reliably and efficiently direct the operation of Hydro One's transmission network. The IESO is of the view that reduced transmission losses are not a reliable indicator of the IESO's success in fulfilling the agreement and/or of achieving overall cost effectiveness.

f) As noted in Exhibit A-1-1, forecast losses of 2.6 TWh are allocated to domestic customers for calculating the domestic usage fee and 0.4 TWh are allocated to export customers for the export usage fee. Please refer to the response to VECC Interrogatory 3 at Exhibit I, Tab 2.0, Schedule 9.03 for an update of these forecasts.

g) Please refer to the responses to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03; ED Interrogatory 7 at Exhibit I, Tab 5.1, Schedule 4.07; ED Interrogatory 9 at Exhibit I, Tab 5.1, Schedule 4.09; and ED Interrogatory 12 at Exhibit I, Tab 5.1, Schedule 4.12.

BOMA INTERROGATORY 24

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p38***

(a) Has the IESO provided an MD&A from 2016, or any earlier year? Where is this found? Is it a part of the IESO's Annual Reports?

(b) What is the purpose of the $10 million cash reserve (ratepayer loan)? Why is it necessary for the IESO, when it is not necessary for other regulated entities/LDCs? Please discuss fully.

RESPONSE

(a) The IESO has not provided a Management Discussion and Analysis ("MD&A") in 2016 as the draft scorecard provided in this application is the first scorecard submitted by the IESO and it is based on the June 2, 2017 IESO Regulatory Scorecard Report prepared by Elenchus.

(b) The Board-approved $10 million operating reserve provides funds for the IESO to deal with unexpected budget variances. Objectives of maintaining this reserve include funding the IESO's operations in the event of revenue shortfalls or unanticipated expenditures. Please see the response to OEB Staff Interrogatory 8 Exhibit I, Tab 4.1, Schedule 1.8, OEB Staff Interrogatory 9 Exhibit I, Tab 4.2, Schedule 1.9 and OEB Staff Interrogatory 10 Exhibit I, Tab 4.3, Schedules 1.10.

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BOMA INTERROGATORY 25

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p41***

Is the IESO prepared to undertake the development of performance measurement for its contract negotiation and management functions? What efforts have been made to date to do this?

RESPONSE

The IESO has not undertaken such efforts as this was not a recommended measurement in the Elenchus report, no efforts have been made to date to do this.

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BOMA INTERROGATORY 26

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p44***

Please provide a copy of the Norton/Kaplan HBIL HBR article on performance scorecards.

RESPONSE

A copy of the Norton/Kaplan HBIL HBR articles on performance scorecards is provided as Attachments 1 and 2.

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HARVARD | BUSINESS | SCHOOL

Conceptual Foundations of the Balanced Scorecard

Robert S. Kaplan

Working Paper

10-074

Conceptual Foundations of the Balanced Scorecard[1]

Robert S. Kaplan

Harvard Business School, Harvard University

[1] Paper originally prepared for C. Chapman, A. Hopwood, and M. Shields (eds.), *Handbook of Management Accounting Research: Volume 3* (Elsevier, 2009).

Conceptual Foundations of the Balanced Scorecard

Abstract

David Norton and I introduced the Balanced Scorecard in a 1992 *Harvard Business Review* article (Kaplan & Norton, 1992). The article was based on a multi-company research project to study performance measurement in companies whose intangible assets played a central role in value creation (Nolan Norton Institute, 1991). Norton and I believed that if companies were to improve the management of their intangible assets, they had to integrate the measurement of intangible assets into their management systems.

After publication of the 1992 HBR article, several companies quickly adopted the Balanced Scorecard giving us deeper and broader insights into its power and potential. During the next 15 years, as it was adopted by thousands of private, public, and nonprofit enterprises around the world, we extended and broadened the concept into a management tool for describing, communicating and implementing strategy. This paper describes the roots and motivation for the original Balanced Scorecard article as well as the subsequent innovations that connected it to a larger management literature.

"Conceptual Foundations of the Balanced Scorecard"

Robert S. Kaplan

David Norton and I introduced the Balanced Scorecard in a 1992 *Harvard Business Review* article.[1] The article was based on a 1990 Nolan, Norton multi-company research project that studied performance measurement in companies whose intangible assets played a central role in value creation.[2] Our interest in measurement for driving performance improvements arose from a belief articulated more than a century earlier by a prominent British scientist, Lord Kelvin:[3]

> I often say that when you can measure what you are speaking about, and express it in numbers, you know something about it; but when you cannot measure it, when you cannot express it in numbers, your knowledge is of a meager and unsatisfactory kind.
>
> If you can not measure it, you can not improve it.

Norton and I believed that measurement was as fundamental to managers as it was for scientists. If companies were to improve the management of their intangible assets, they had to integrate the measurement of intangible assets into their management systems.

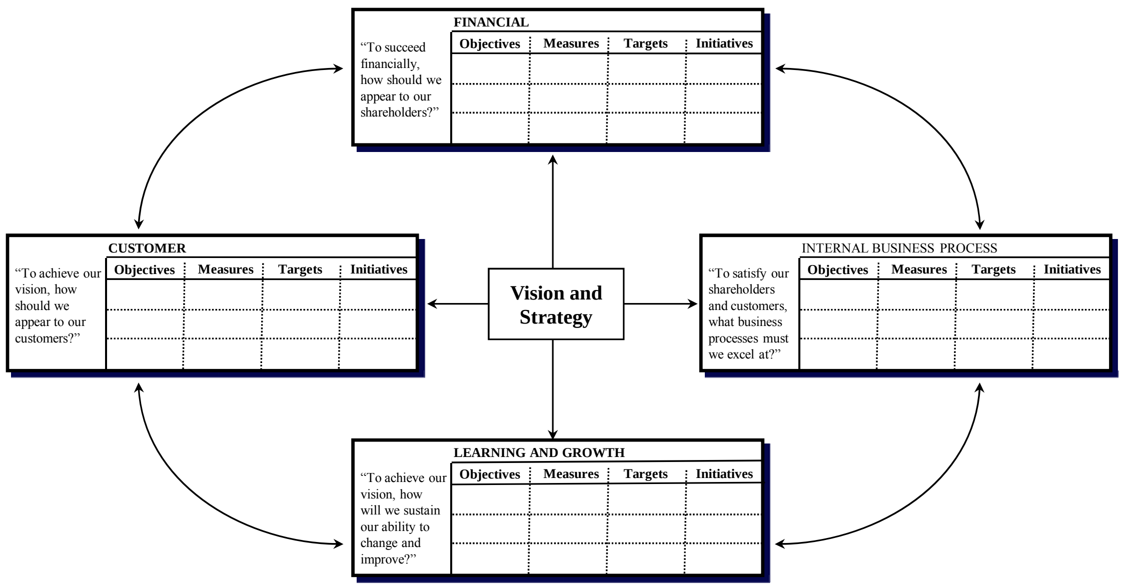
After publication of the 1992 HBR article, several companies quickly adopted the Balanced Scorecard giving us deeper and broader insights into its power and potential. During the next 15 years, as it was adopted by thousands of private, public, and nonprofit enterprises around the world, we extended and broadened the concept into a management tool for describing, communicating and implementing strategy. In this paper, I describe the roots and motivation for the original Balanced Scorecard article as well as the subsequent innovations that connected it to a larger management literature. The paper uses the following structure for organizing the origin and subsequent development of the Balanced Scorecard:

1. Balanced Scorecard for Performance Measurement
2. Strategic Objectives and Strategy Maps
3. The Strategy Management System
4. Future Opportunities

Balanced Scorecard for Performance Measurement

Figure 1 shows the original structure for the Balanced Scorecard (BSC). The BSC retains financial metrics as the ultimate outcome measures for company success, but supplements these with metrics from three additional perspectives – customer, internal process, and learning and growth – that we proposed as the drivers for creating long-term shareholder value.

Figure 1: Translating Vision and Strategy: Four Perspectives



1.1. Historical Roots: 1950-1980

The Balanced Scorecard, of course, was not original for advocating that nonfinancial measures be used to motivate, measure, and evaluate company performance. In the 1950s, a General Electric corporate staff group conducted a project to develop performance measures for

GE's decentralized business units (Lewis, 1955).[2] The project team recommended that divisional performance be measured by one financial and seven nonfinancial metrics.

1. Profitability (measured by residual income)
2. Market share
3. Productivity
4. Product leadership
5. Public responsibility (legal and ethical behavior, and responsibility to stakeholders including shareholders, vendors, dealers, distributors, and communities)
6. Personnel development
7. Employee attitudes
8. Balance between short-range and long-range objectives

One can see the roots of the Balanced Scorecard in these eight objectives. The financial perspective is represented by the first GE metric, the customer perspective with the second, the process perspective with metrics 3 -5, and the learning and growth perspective with metrics 6 and 7. The 8th metric captures the essence of the Balance Scorecard, encouraging managers to achieve a proper balance between short and long-range objectives. Unfortunately, the noble goals of the 1950s GE corporate project never got ingrained into the management system and incentive structure of GE's line business units. In fact, despite metrics 5 and 8 in the above list, several GE units were subsequently convicted of price-fixing schemes, with their managers claiming that corporate pressure for short-term profits led them to compromise long-term objectives and their public responsibilities.

At about the same time as the GE project, Herb Simon and several colleagues at the newly-formed Graduate School of Industrial Administration, Carnegie Institute of Technology (later Carnegie-Mellon University) identified several purposes for accounting information in organizations:

Scorecard questions: "Am I doing well or badly?"

Attention-directing questions: "What problems should I look into?"

Problem-solving questions: "Of the several ways of doing the job, which is the best?

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[2] See also, General Electric (A), HBS Case Study

Simon and his colleagues explored the role for financial and nonfinancial information to inform these three questions. This study was perhaps the first to introduce the term "scorecard" into the performance management discussion.

Peter Drucker introduced management by objectives in his classic 1954 book, *The Practice of Management*. Drucker argued that all employees should have personal performance objectives that aligned strongly to the company strategy:

> Each manager, from the "big boss" down to the production foreman or the chief clerk, needs clearly spelled-out objectives. These objectives should lay out what performance the man's [sic] own managerial unit is supposed to produce. They should lay out what contribution he and his unit are expected to make to help other units obtain their objectives. […] These objectives should always derive from the goals of the business enterprise. […] [M]anagers must understand that business results depend on a balance of efforts and results in a number of areas. […] Every manager should responsibly participate in the development of the objectives of the higher unit of which his is a part. […] He must know and understand the ultimate business goals, what is expected of him and why, what he will be measured against and how (Drucker 1954, pp. 126-9).

Despite Drucker's insights and urgings, however, management by objectives in the next half-century mostly became a somewhat bureaucratic exercise, administered by the human resources department, based on local goal-setting that was operational and tactical, and rarely informed by business-level strategies and objectives. Companies at Drucker's time and for many years thereafter lacked a clear way of describing and communicating top-level strategy in a way that middle managers and front-line employees could understand and internalize.

In the mid-1960s, Robert Anthony, building upon the decade-earlier research by Simon et al, and on another article by Simon on programmed versus nonprogrammed decisions, proposed a comprehensive framework for planning and control systems. Anthony identified three different types of systems: strategic planning, management control, and operational control. Strategic planning was defined as:

> the process of deciding upon objectives, on changes in these objectives, on the resources used to attain these objectives, and on the policies that are to govern the acquisition, use, and disposition of these resources (Anthony 1965, p.16).

Foreshadowing the subsequent development of strategy maps, Anthony claimed that strategic planning depends "on an estimate of a cause-and-effect relationship between a course of action and a desired outcome," but concluded that, because of the difficulty of predicting such a relationship, "strategic planning is an art, not a science." Further, Anthony noted that strategic planning is not accompanied by what we would today call strategic control, "Although strategic revision is important, top management spends relatively little time in this activity." Anthony also believed that information for strategic planning usually had a financial emphasis.

Anthony's second category, management control, concerned "the process by which managers assure that resources are obtained and used effectively and efficiently in the accomplishment of the organization's objectives" (Anthony 1965, p. 17). He observed that management control systems, with rare exceptions, have an underlying *financial* structure; that is, plans and results are expressed in monetary units … the only common denominator by means of which the heterogeneous elements of outputs and inputs can be combined and compared. He acknowledged, however,

> Although management control systems have financial underpinnings, it does not follow that money is the only basis of measurement, or even that it is the most important basis. Other quantitative measurements, such as […] market share, yields, productivity measures, tonnage of output, and so on, are useful. (Anthony 1965, p. 42)

Anthony described the third category, operational or task control, as "the process of assuring that specific tasks are carried out effectively and efficiently." He stated that information for operational control was mostly nonmonetary, though some information could be denominated in monetary terms (presumably, frequent variance reports on labor, machine, and materials quantity and cost variances).

Thus the roots of management planning and control systems encompassing both financial and nonfinancial measurement can be seen in these early writings of Simon, Drucker, and Anthony. Despite the advocacy of these scholars, however, the primary management system for most companies, until the 1990s, used financial information almost exclusively and relied heavily on budgets to maintain focus on short-term performance.

1.2. Japanese Management Movement: 1975-1990

During the 1970s and 1980s, innovations in quality and just-in-time production by Japanese companies challenged the Western leadership in many important industries. Several authors argued that Western companies' narrow focus on short-term financial performance contributed to their complacency and slow response to the Japanese threat. Johnson and Kaplan (1987) reviewed the history of management accounting and concluded that US corporations had become obsessed with short-term financial measures and had failed to adapt their management accounting and control systems to the operational improvements from successful implementation of total quality and short-cycle-time management.

A Harvard Business School project on Council on Competitiveness (Porter, 1992) echoed these critiques when it identified the following systematic differences between investments made by US corporations versus those made in Japan and Germany:

> The US system is less supportive of investment overall because of its sensitivity to current returns … combined with corporate goals that stress current stock price over long-term corporate value.
>
> The US system favors those forms of investment for which returns are most readily measurable. … This explains why the United States underinvests, on average, in intangible assets [N.B., product and process innovation, employee skills, customer satisfaction] where returns are more difficult to measure.
>
> The US system favors acquisitions, which involve assets that can be easily valued over internal development projects that are more difficult to value. (Porter, 1992, p. 72-73).

Some accounting academics proposed methods by which a firm's spending to create intangible assets could be capitalized and placed as assets on the corporate Balance Sheet. During the 1970s, there was a burst of interest in human resources accounting (Flamholtz, 1974; Caplan and Landekich, 1975; Grove et al, 1977). Subsequently, Baruch Lev and his doctoral students and colleagues proposed that financial reporting could be more relevant if companies capitalized their expenditures on intangible assets or found other methods by which these assets could be placed on corporate Balance Sheets. While such a treatment is consistent with Lord Kelvin's (and our) advocacy of measurement to improve understanding and management, none of these approaches gained traction in actual companies. Several factors led to the lack of adoption of placing values for intangible assets on corporate Balance Sheets.

First, the value from intangible assets is indirect. Assets such as knowledge and technology seldom have a direct impact on revenue and profit. Improvements in intangible assets affect financial outcomes through chains of cause-and-effect relationships involving two or three intermediate stages. For example, consider the linkages in the service management profit chain (Heskett et al, 1994; Heskett, Sasser and Schlesinger, 1997), a development done in parallel and consistent with our Balanced Scorecard approach:

- investments in employee training lead to improvements in service quality
- better service quality leads to higher customer satisfaction
- higher customer satisfaction leads to increased customer loyalty

- increased customer loyalty generates increased revenues and margins.

Financial outcomes are separated causally and temporally from improving employees' capabilities. The complex linkages make it difficult if not impossible to place a financial value on an asset such as workforce capabilities or employee morale, much less to measures changes from period to period in such a financial value.

Second, the value from intangible assets depends on organizational context and strategy. This value cannot be separated from the organizational processes that transform intangibles into customer and financial outcomes. A corporate Balance Sheet is a linear, additive model. It records each class of asset separately and calculates the total by adding up each asset's recorded value. The value created from investing in individual intangible assets, however, is neither linear nor additive.

Senior investment bankers in a firm such as Goldman Sachs are immensely valuable because of their knowledge about complex financial products and their capabilities for managing relationships and developing trust with sophisticated customers. People with the same knowledge, experience, and capabilities, however, are nearly worthless to a financial services company such as etrade.com that emphasizes operational efficiency, low cost, and technology-based trading. The value of an intangible asset depends critically on the context – the organization, the strategy, and other complementary assets – in which the intangible asset is deployed.

Also, intangible assets seldom have value by themselves.[3] Generally, they must be bundled with other intangible and tangible assets to create value. For example, a new growth-oriented sales strategy could require new knowledge about customers, new training for sales employees, new databases, new information systems, a new organization structure, and a new incentive compensation program. Investing in just one of these capabilities, or in all of them but one, could cause the new sales strategy to fail. The value does not reside in any individual intangible asset. It arises from creating the entire set of assets along with a strategy that links them together. The value-creation process is multiplicative, not additive.

Rather than attempt a solution to the measurement and management of intangible assets within the financial reporting framework, several articles and books in the 1980s recommended that companies integrate nonfinancial indicators of their operating performance into their management accounting and control systems, e.g. Howell et al. (1987), Berliner and Brimson

[3] Brand names, which can be sold, are an exception.

(1991), Kaplan (1990). Some authors went further when they urged that internal reporting of financial information to managers and employees, especially those tasked with improving operations by continuous improvement of quality, process yields, and process cycle times, be abolished.

> Managing with information from financial accounting systems impedes business performance today because traditional cost accounting data do not track sources of competitiveness and profitability in the global economy. Cost information, per se, does not track sources of competitive advantage such as quality, flexibility and dependability. […] Business needs information about activities, not accounting costs, to manage competitive operations and to identify profitable products (Johnson, 1980, 44-5).

Essentially, these authors argued that companies should focus on improving quality, reducing cycle times, and improving companies' responsiveness to customers' demands. Doing these activities well, they believed, would lead naturally to improved financial performance.

The US Government in 1987 introduced the Malcolm Baldrige National Quality Award to promote quality awareness, recognize quality achievements, and publicize successful quality strategies. The initial set of Baldrige criteria included financial metrics (profits per employee), customer-perceived quality metrics (market cycle time, late deliveries), internal process metrics (defects, total manufacturing time, order entry time, supplier defects) and employee metrics (training per employee, morale). But in the early 1990s, several studies revealed that even businesses that had received the Baldrige Award for quality excellence could encounter financial difficulties, suggesting that the link, assumed by the academic scholars quoted above, between continuous process improvement and financial success was far from automatic.

During the late 1980's, I wrote several case studies that described how some companies had integrated well financial information with nonfinancial information on process quality and cycle times for front-line employees. In an operating department of a large chemical company,[4] a chemical-engineer department manager had introduced a daily income statement for the operators in his department. Even though the employees already had access (every 2-4 hours) to thousands of observations about operating parameters, throughput, and quality, the new daily income statement proved a big hit, and helped the employees set production records for throughput and quality. The daily income statement helped employees quickly assess the consequences from off-spec production or machine downtime, enabled them make trade-offs among conflicting demands on quality and throughput, and guided and justified their decisions about spending to improve quality and throughput.

4 "Texas Eastman Company," HBS Case #9-190-039.

Another case described how a Big-3 automobile engine fabrication plant had made a deep commitment to total quality management principles. It provided decentralized work teams with continuous information about machine downtime and scrap to facilitate operational improvements at bottleneck machines and processes, and to eliminate the root causes of scrap and off-spec production. But in addition to the daily information on machine downtime, throughput and scrap (all nonfinancial measures), the work teams received a daily report on their spending on indirect materials, such as supplies, tools, scrap and maintenance materials, plus a weekly report on total overhead expenses charged to their departments, including telephone, utilities, indirect labor, and salaries of engineering and technical assistants. Plant management wanted the teams not only to improve quality and throughput but also to make decisions that could directly influence the costs being incurred in their departments.[5] These two cases revealed the power of complementing nonfinancial information with financial information, even for front-line production employees.

A third case, about a semiconductor company, Analog Devices, described how executives at the top of the organization benefited from seeing nonfinancial information. Analog Devices, like the chemicals plant and the Big-3 automobile engine plant, had introduced a highly successful quality management system, which included an innovative quality improvement metric.[6] In addition, Analog's vice president of quality and improvement, an experienced Baldrige Award examiner, had translated the Baldrige criteria into an internal corporate scorecard for his executive team. The corporate scorecard included some high-level financial metrics that the executive team had been accustomed to managing, but also the Baldrige quality metrics organized by three other perspectives:

- customer quality metrics, such as on-time delivery, lead time, and customer-measured defects
- manufacturing process metrics, such as yield, part-per-million defect rates, and cycle times
- employee metrics, such as absenteeism and lateness.

The Analog scorecard signaled that to make quality improvement a senior executive focus, the measurement system should be expanded beyond financial indicators to include an array of quality metrics relating to customers, manufacturing processes, and employees.

The three cases provided successful counter-examples to the various scholars and consultants who argued that front-line employees need see only nonfinancial indicators while

5 "Romeo Engine Plant," Harvard Business School Case #9-194-032
6 "Analog Devices: The Half-Life System," HBS Case #9-190-061.

senior management can and should focus only on financial ones. The cases showed how front-line employees could benefit from seeing financial metrics, while senior executive teams benefited from supplementing their financial view of the world with metrics about customers, quality, and employees. Thus the stage was set for thinking about a general framework by which both senior-level executive teams and front-line production workers would receive financial and nonfinancial information.

1.3. Shareholder Value and the Principal-Agent Framework

Not all academics, however, had been exposed to the recent advances in operations management. Many remained focused on economics and finance, especially the efficient markets theory from the 1960s and early 1970s (Fama, 1971). Economists also introduced principal-agent theory (Jensen-Meckling, 1976, Harris-Raviv, 1979; Holmström, 1979, Grossman-Hart, 1983) to formalize the inherent conflict of interests between hired executive teams and the companies' dispersed shareholders (owners). The principal-agent adherents urged companies to provide more financial incentives to senior executive teams, especially incentives based on financial performance, the typical "outcome" measure assumed in principal-agent models. Efficient markets research; suggested that stock prices continually reflected all the relevant public information about companies' performance, and that executives' compensation could be better aligned with owners' interests through expanded use of stock options and other equity rewards (Jensen-Meckling, 1976; Fama-Jensen, 1983). In a similar vein, some argued for aligning compensation to better accounting surrogates of stock market performance, especially residual income under its new name, economic value added (Stewart, 1991).

The 1980s saw a huge increase in the linkage between executives' pay and incentives to financial performance. For the financial economists at the vanguard of this movement, the idea of senior executives paying attention to nonfinancial performance metrics was close to blasphemous. As Michael Jensen (2001), a leading financial economics scholar, has stated:

> Balanced Scorecard theory is flawed because it presents managers with a scorecard which gives no score – that is no single-valued measure how they have performed. Thus managers evaluated with such a system […] have no way to make principled or purposeful decisions.

I obviously agree with Jensen that managers cannot be paid by a set of unweighted performance metrics. Ultimately, if a company wants to set bonuses based on measured performance, it must reward based on a single measure (either a stock market or accounting-based metric) or provide a weighting among the multiple measures a manager has been instructed to improve. But linking performance to pay is only one component of a comprehensive management system.

Consider an airplane where passengers contract with the pilot for a safe and on-time journey. One can imagine an airplane cockpit designed by a financial economist. It consists of a single instrument that displays the destination to be achieved and the desired time of arrival. Or, the pilot is given a more complex navigation instrument where the movement of the needle represented a weighted average of estimated time to arrival, fuel remaining, altitude, deviation from expected flight path, and proximity to other airplanes. Few of us would feel comfortable flying in a plane guided only by the single instrument even though the incentives of the pilot and the passengers for a safe, on-time arrival are perfectly aligned. Incentives are important, but so also are information, communication, and alignment.

1.4. Uncertainty and Multi-Period Optimization

Many of the principal-agent models developed by economists and finance scholars are single-period in which the firm's output gets revealed at the end of the period and no further managerial (agent) actions are required. In these cases, contracting on output, such as measured financial performance, can be optimal. Or, if financial performance, measured by end-of-period stock price or economic value added, is a complete and sufficient statistic for the value managers have created during the period, then incentive contracts based on stock prices or economic value added can also be optimal. But many of the actions that managers take during a period – such as upgrading the skills and motivation of employees, advancing products through the research and development pipeline, improving the quality of processes, and enhancing trusted relationships with customers and suppliers – are not revealed to public investors so that their implications for firm value cannot be incorporated into end-of-period stock prices. Also, while managers may know the amount they spent on enhancing their intangible assets, they may have little idea, in the short-run, about how much value they have created. And, for sure, such value increases (or decreases if the expenditures do not generate future value in excess of the amount spent) do not get incorporated into the end-of-period stock price or residual value (economic value added) metric.

Dynamic programming teaches us that the optimal actions in the first period of a multi-period model are far from the optimal actions in the final period. Managers attempting to maximize total shareholder value over, say, a ten year period cannot accomplish this goal by optimizing reported financial performance or stock price, period-by-period. The Balanced Scorecard recognizes the limitation of managing to financial targets alone in short-time horizons when managers are following a long-term strategy of enhancing the capabilities of their customer and supplier relationships, operating and innovation processes, human resources, information resources, and organizational climate and culture. But because the links from process improvements and investments in intangible assets to customer and financial outcomes are uncertain (recall the financial problems of several of the early excellent-quality companies), the Balanced Scorecard includes the outcome metrics as well to signal when the long-term strategy appears to be delivering the expected and desired results.

1.5. Stakeholder Theory

Stakeholder theory offers another multi-dimensional approach for enterprise performance measurement. Stakeholders are defined as the groups or individuals, inside or outside the enterprise, that have a stake or can influence the organization's performance. The theory generally identifies five stakeholder groups for a company: three of them, shareholders, customers, and communities, define the external expectations of a company's performance; the other two, suppliers and employees, participate with the company to plan, design, implement and deliver the company's products and services to its customers (Atkinson et al., 1997, p. 27). Management control scholars who apply stakeholder theory to performance measurement, believe "performance measurement design starts with stakeholders" (Neely and Adams, 2002). The stakeholder approach to performance measurement starts by defining objectives for what each stakeholder group expects from the corporation and how each group contributes to the success of the corporation. Once stakeholder expectations or, even further, implicit and explicit contracts between the stakeholders and the corporation get defined, the corporation then defines a strategy to meet these expectations and fulfill the contracts. Thus, while the Balanced Scorecard approach starts with strategy and then identifies the inter-relationships and objectives for various stakeholders, the stakeholder approach starts with stakeholder objectives and, in a second step, defines a strategy to meet shareholder expectations.

Just as Chandler articulated that strategy precedes structure, I strongly believe that strategy also precedes stakeholders. The stakeholder movement likely developed to counter the narrow shareholder value maximization view articulated by Milton Friedman and, subsequently, financial economists, such as Jensen. In this spirit, I believe the stakeholder helped us appreciate the value from nurturing multiple relationships that drive long-term and sustainable value creation. But stakeholder theory confuses means and ends, and therefore ends up less powerful, less actionable, and, ultimately, less satisfying (at least to me) than the strategy map/Balanced Scorecard approach. We advocate selecting a strategy first, and only subsequently working out the relationship with stakeholders, as needed by the strategy. I will illustrate my point of view with two examples.

First, let's take the example of Mobil's US Marketing and Refining, a well-documented Balanced Scorecard implementation.[7] Mobil learned, through marketing research, that its customers were heterogeneous. Some valued low price only; for them Mobil should offer the cheapest prices, matching or beating the prices of discount stations and the other major gasoline companies. Other customers, however, were not so price sensitive and were willing to pay a price premium, say up to $0.10-0.12 per gallon, if they could have a superior buying experience (quick serve, pay by credit cards at the pump, clean rest rooms, friendly helpful employees, great convenience store, etc.). Stakeholder theory fails here. Which customers' expectations should Mobil satisfy? It could not be the best for both customer groups. Having larger gasoline stations, with more pumps, equipped with self-pay mechanisms, better-paid and more trained and experienced employees, and a full service convenience store costs money, and these costs would need to be covered by higher prices, thereby disappointing the price-sensitive customers. If Mobil offered the lowest prices, it could not afford to invest in the employees, the convenience store, and the larger stations with more self-service and self-pay pumps, thereby disappointing the customers desiring a great buying experience.

Strategy is about choice. Companies cannot meet the expectations of all their possible customers. Wal-Mart meets the apparel needs of one market segment of customers (price-sensitive), Nordstrom meets the needs of another segment (customer relationships and solutions), and Armani and Ferragamo meet the expectations of a third segment (product-leading fashion, fabric, and fit; price-insensitive). Similarly, customers of Southwest Airlines have different expectations of performance than the business and first class customers who fly British Airways. Strategy determines which customers the company has decided to serve and the value proposition that it will offer to win the loyalty of those customer segments. The determination of strategy must come before defining measures of customer satisfaction and loyalty. Otherwise, following the recommendations of the stakeholder theorists, the company would attempt to meet the expectations of all the existing and potential customers it could serve, getting stuck "in the middle," as described by Michael Porter, with both a high cost and a non-differentiated approach, a recipe for strategy failure.

A similar situation occurs for employees. The Balanced Scorecard deliberately did not label its fourth perspective the "employees" or "people" perspective, choosing a more generic

[7] "Mobil US Marketing and Refining (A)," Harvard Business School Case # 197-025.

name, “learning and growth,” to signal that we were not taking a pure stakeholder approach. Under the BSC approach, employee objectives always appear (in the learning and growth perspective) but they get there because they are necessary for the *strategy*, not because someone has labeled them as a “stakeholder.” Consider a pharmaceutical company in the early 1990s. One of its most important groups of employees (what we would subsequently call a strategic job family) is the chemists performing research to screen and identify new compounds to treat specific diseases. The stakeholder approach would interview these key employees to learn their career expectations and develop a strategy that would meet their expectations and strive to continually motivate and satisfy these employees.

During the 1990s, however, and continuing into this century, the key scientific discipline for new drug development shifted from chemistry to biology. The new key employees became molecular biologists and geneticists. Pharmaceutical companies shifted their strategies to adapt to the new technologies; the fate of their previous key stakeholder, Ph.D. chemists, became more tenuous, especially if they did not acquire dramatic new capabilities and competencies so that they could contribute to new drug development. Again, the stakeholder view would lock the company into maintaining relationships with its soon-to-be-obsolete employee group and not moving swiftly enough to reflect that it needed entirely new employees to help it implement the new strategy.

Stakeholder theorists also criticize the Balanced Scorecard for not having a separate perspective for suppliers, one of their five essential stakeholder groups. But as with employees, suppliers get on the scorecard (typically in the Process perspective) when they are essential to the strategy. So companies, such as Wal-Mart, Nike and Toyota, for whom suppliers provide a critical component in creating sustainable competitive advantage, would certainly feature supplier performance in their strategy maps. But, consider a company like Mobil US Marketing and Refining, whose main suppliers are petroleum exploration and production companies, providing a commodity, such as crude oil, and construction companies, who build refineries and pipelines. These suppliers provide essential products and services but don’t provide any differentiation or support of Mobil’s strategy. Similarly, a community bank following a customer intimacy strategy gets its raw material, money, from the US Federal Reserve system. Suppliers are not a critical component of its strategy. So Mobil USM&R and the community bank may not feature suppliers on their scorecards because they don’t contribute to the differentiation and sustainability of their strategies. Again, strategy precedes stakeholders and, in this case, may reveal that one of the stakeholder categories is not decisive for the strategy.

Finally, the Balanced Scorecard does include performance in communities as process perspective objectives when such performance does contribute to the differentiation in the strategy (Kaplan and Norton, 2003). This view matches that articulated by Michael Porter when he advocates that environmental and social performance be aligned to and support the company strategy (Porter and Kramer, 1999, 2006). Occasionally companies do not want shareholder value to be the unifying paradigm for its strategy. That's ok; it's their choice. They don't have to abandon the Balanced Scorecard methodology and switch to the stakeholder view. They can use a strategy map and Balanced Scorecard to articulate their strategy that attempts to simultaneously create economic, environmental and social value, and to balance and manage the tensions among them. This is exactly the path taken by Amanco, a Latin American producer of water treatment solutions, whose founding shareholder believed deeply in triple-bottom line performance.[8]

In summary, stakeholder theory was useful to articulate a broader company mission beyond a narrow, short-term shareholder value-maximizing model. It increased companies' sensitivity about how failure to incorporate stakeholder preferences and expectations can undermine an excessive focus on short-term financial results. The Balanced Scorecard, however, incorporates stakeholder interests endogenously, within a coherent strategy and value-creation framework, when outstanding performance with those stakeholders is critical for the success of the strategy. The converse is not true for stakeholder theory. It does not enable companies to develop a strategy when some of the existing "stakeholders" are no longer essential or even desirable in light of changes in the external environment and internal capabilities.

1.5. Integration and Summary

Dave Norton and I introduced the Balanced Scorecard to provide a missing component and bridge among these various apparently conflicting literatures that had been developed in complete isolation from each other: the literature on quality and lean management, which emphasized employees' continuous improvement activities to reduce waste and increase company responsiveness; the literature on financial economics, which placed heightened emphasis on financial performance measures; and the stakeholder theory where the firm was an intermediary attempting to forge contracts that satisfied all its different constituents. We attempted to retain the valuable insights from each. Employee and process performance are critical for current and future success. Financial metrics, ultimately, will increase if companies' performance improves. And to optimize long-term shareholder value, the firm had to internalize the preferences and expectations of its shareholders, customers, suppliers, employees, and communities. The key was to have a

[8] "Amanco: Developing the Sustainability Scorecard," HBS Case # 107-038.

more robust measurement and management system that included both operational metrics as leading indicators and financial metrics as lagging outcomes, along with several other metrics to measure a company's progress in driving future performance.

This insight became glaringly obvious to us during our initial 1990 multi-company research project when we invited the innovative vice-president of quality and productivity at Analog Devices, Arthur Schneiderman, to address our group. At the end of the presentation, in response to a question about how the company was doing with its quality improvement metric and corporate scorecard, he reported that every quality measure on its corporate scorecard had experienced dramatic improvements. He also noted, however, that the company's stock price had decreased by nearly 70% during the past three years. The company had failed to translate its improved manufacturing and delivery performance into increased sales and margins, and the stock price reflected this shortcoming. The failure to include the link between quality improvements on Analog's quality scorecard to a customer value proposition or to any customer outcomes likely contributed to the shareholder value loss. Norton and I recognized that any comprehensive measurement and management system had to link operational performance improvements to customer and financial performance. Our Balanced Scorecard, while incorporating Analog's operational improvement metrics, also incorporated metrics for innovation, employee capabilities, technology, organizational learning, and customer success. And unlike the stakeholder perspective, we did place shareholder value as the highest-level metric, with all the other stakeholders reflected in how they contributed to the company's success in maximizing long-term shareholder value.

2. Strategic Objectives

As Norton and I began working with the companies, after the initial HBR article appeared, we faced the question about how to choose the metrics that would go on a Balanced Scorecard. We could have adopted the generic metrics that many companies were already using, such as customer satisfaction, customer retention, defect rates, yields, lead and process times, and employee satisfaction. But the client companies and we were dissatisfied with these metrics. They were too generic. By 1992, virtually all companies (airlines and dysfunctional companies, such as WorldCom, being notable exceptions) were attempting to increase customer satisfaction, improve process quality, and motivate employee performance. As we probed this issue with executives, we quickly learned that creating a Balanced Scorecard should not start with selecting metrics.

Many companies, however, already had extensive measurements from their existing quality and performance improvement programs and wanted to create a quick Balanced Scorecard by classifying each of their existing metrics into one of the four BSC perspectives. While having a structure for reporting their nonfinancial metrics was better than having no nonfinancial metrics or simply a long list of them, this bottoms-up process of classifying existing measurements was unlikely to capture the most important drivers of future success.

A second group of companies looked externally for their metrics and conducted benchmarking studies to learn the metrics used by the companies they admired most. Norton and I did not want the Balanced Scorecard to become a benchmarking exercise. We knew that even high-performing companies succeeded with strategies that were quite different from each other. The metrics used by a company following a low cost strategy (WalMart, for example) should be distinct from those used by a company implementing a complete customer solutions strategy (e.g., Nordstrom) or a company with an innovative product leadership strategy (e.g., Armani and Ferragamo). Adopting metrics used by a company with a different strategy would confuse and distract the focus of employees and cause the strategy to fail.

Company executives continually told us that their highest priority was implementing their strategy. We came to recognize that before selecting metrics, companies should describe what they were attempting to achieve with their strategies, and, further, that the four BSC perspectives provides a robust structure for companies to express their strategic objectives. The financial objective would include a high-level objective for sustained shareholder value creation and supporting sub-objectives for revenue growth, productivity, and risk management. The customer perspective would include objectives for desired customer outcomes, such as to acquire, satisfy, and retain targeted customers, and to build the share of their spending done with the company.

In addition to these somewhat generic lagging measures of customer performance, we recognized that companies needed to express objectives for the value proposition they offered customers. The value proposition, the unique combination of price, quality, availability, ease and speed of purchase, functionality, relationship and service, was the heart of the strategy, what differentiated the company from its competitors or what it intended to do better than they for the targeted customers. Thus companies following a low cost strategy would offer low prices, defect-free products and speedy purchase. Product innovating companies offered products and services whose performance exceeded that of competitors along dimensions that targeted customers valued.

Objectives in the process perspective reflected how the company would create and deliver the differentiated value proposition and meet the financial objectives for productivity improvements. Objectives in the learning and growth perspectives described the goals for employees, information systems, and organizational alignment.

Over the years, we learned new ways to write strategic objectives. Many companies now write their strategic objectives in quotes to reflect the voice of their customers and employees. For example, one medium-sized community bank that was shifting from its traditional product push strategy to one that emphasized developing complete financial solutions for its targeted customers expressed its customer objectives as:

1. "Understand me and give me the right information and advice"
2. "Give me convenient access to the right products"
3. "Appreciate me and get things done easily, quickly, and right"

Each of these customer objectives, once identified, could be easily measured, such as by the following list:

1a. Number of customers profiled
1b. Number of customers with financial plans
2. Number of targeted customer using on-line channel for transactions
3. Customer survey responses on questions related to appreciation and ease of working with the bank.

Similarly, the learning and growth objectives, written in the voice of employees, included:

"We hire, develop, retain, and reward great people"
"We are trained in the skills we need to succeed."
"We understand the strategy and know what we need to do to implement it"
"We have the information and tools we need to do our job."

As with the customer objectives, once the employee objectives had been selected and expressed, it was a simple task to select metrics that measured the performance for each of these strategic objectives. These metrics were more aligned to the strategy than generic metrics of employee morale and satisfaction.

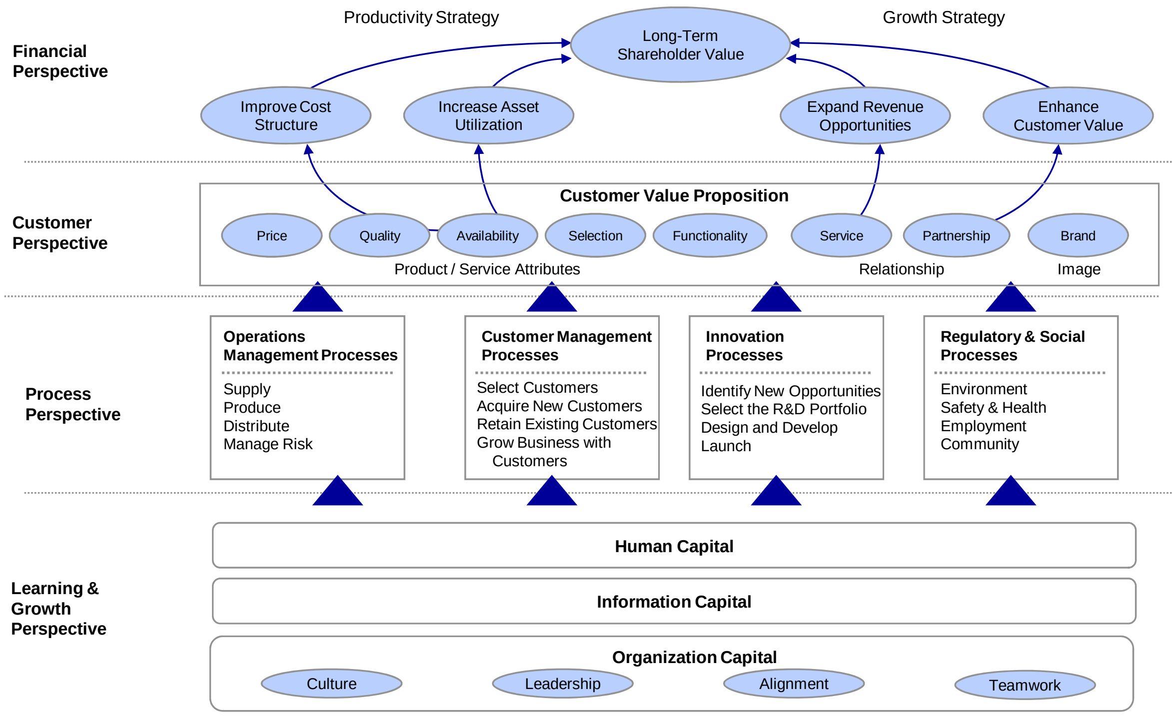
Thus, while our initial article had a subtitle, "Measures that Drive Performance," we soon learned that we had to start not with measures but with descriptions of what the company wanted to accomplish. It turned out that selection of measures was much simpler after company executives described their strategies through the multiple strategic objectives in the four BSC perspectives.

3. Strategy Maps

It soon became natural to describe the causal relationships between strategic objectives. For example, a simple causal chain of strategic objectives would be: employees better trained in quality management tools reduce process cycle times and process defects; the improved processes lead to shorter customer lead times, improved on-time delivery, and fewer defects experienced by customers; the quality improvements experienced by customers lead to higher satisfaction, retention, and spending, which drives, ultimately, higher revenues and margins. All the objectives are linked in cause-and-effect relationships, starting with employees, continuing through processes and customers, and culminating in higher financial performance.

The idea of causal linkages among Balanced Scorecard objectives and measures led to the creation of a strategy map, articulated in an HBR article and several books (Kaplan & Norton 2000, 2001, 2004). **Figure 2** shows the current structure for a strategy map. Today, all BSC projects build a strategy map of strategic objectives first and only afterwards select metrics for each objective.

Figure 2: The strategy map links intangible assets and critical processes to the value proposition and customer and financial outcomes



We recognized that the weakest link in a strategy map and Balanced Scorecard was the learning and growth perspective. For many years, as one executive described it, the learning and growth perspective was "the black hole of the Balanced Scorecard." While companies had some generic measures for employees, such as employee satisfaction and morale, turnover, absenteeism and lateness (probably growing out of the stakeholder movement of the previous decade), none had metrics that linked their employee capabilities to the strategy. A few scholars had investigated the connection between improvements in human resources and improved financial performance (e.g. Huselid, 1995; Becker et al., 1998)

Dave Norton led a research project in 2002 and 2003 with senior HR professionals to explore how to better link the measurement of human resources to strategic objectives. From this work came the concepts of strategic human capital readiness and strategic job families and, by extension, the linkages to information capital and organizational capital. These important extensions to embed the capabilities of a company's most important intangible assets were described in an HBR article and a book (Kaplan & Norton, 2004a&b)

4. Extending Balanced Scorecard to Non-Profit and Public Sector Enterprises

While initially developed for private sector enterprises, the Balanced Scorecard was soon extended to nonprofit and public sector enterprises (NPSEs). Prior to the development of the Balanced Scorecard, the performance reports of NPSEs focused only on financial measures, such as budgets, funds appropriated, donations, expenditures, and operating expense ratios. Clearly, however, the performance of NPSEs cannot be measured by financial indicators. Their success has to be measured by their effectiveness in providing benefits to constituents. The Balanced Scorecard helps NPSEs select a coherent use of nonfinancial measures to assess their performance with constituents.

Since financial success is not their primary objective, NPSEs cannot use the standard architecture of the Balanced Scorecard strategy map where financial objectives are the ultimate, high-level outcomes to be achieved. NPSEs generally place an objective related to their *social impact* and *mission*, such as reducing poverty, pollution, diseases, or school dropout rates, or improving health, biodiversity, education, and economic opportunities. A nonprofit or public sector agency's mission represents the accountability between it and society, as well as the rationale for its existence and ongoing support. The measured improvement in an NPSE's social impact objective may take years to become noticeable, which is why the measures in the other perspectives provide the short- to intermediate-term targets and feedback necessary for year-to-year control and accountability.

One additional modification is required to expand the customer perspective. Donors or taxpayers provide the financial resources—they pay for the service—while another group, the citizens and beneficiaries, receive the service. Both constituents and resource suppliers should be the placed at the top of an NPSE strategy map.

5. The Strategy Management System

My HBS colleague, Robert Simons, developed the Levers of Control management control framework (Simons, 1995a&b) at the same time that Norton and I were developing the Balanced Scorecard. Simons identified several types of management control systems that managers use to motivate, monitor, and manage their strategies. The control systems included belief systems (mission, vision and values), boundary systems, internal control systems, diagnostic systems, and interactive systems. As described at the beginning of this chapter, Norton and I originally envisioned the Balanced Scorecard as an enhanced performance measurement system, labeled by Simons as a diagnostic system. Our vision for the BSC was for managers to define and track performance among multiple financial and nonfinancial measures that were considered important for company success.

Several senior executives soon taught us that the Balanced Scorecard could operate in a far more powerful manner than its use as a management reporting and performance monitoring system. For example, Larry Brady, then President of the FMC Corporation, stated:[9]

> I think that it's important for companies not to approach the scorecard as the latest fad. […] You hear about a good idea, several people on corporate staff work on it, probably with some expensive outside consultants, and you put in a system that's a bit different [incremental] from what existed before.
>
> It gets worse if you think of the scorecard as a new measurement system that eventually requires hundreds and thousands of measurements and a big, expensive executive information system. These companies lose sight of the essence of the scorecard: its focus, its simplicity, and its vision. The real benefit comes from making the scorecard the cornerstone of the way you run the business. It should be the core of the management system, not the measurement system. [It should become] the lever to streamline and focus strategy that can lead to breakthrough performance.

Brady and other early BSC implementation leaders (at Mobil US Marketing and Refining, Cigna Property and Casualty, and Chemical Retail Bank) adopted and used the scorecard to help them describe their strategies and implement a new strategy management system based on scorecard measurements. The new insights helped us formulate the fundamental structure for a generic strategy management system (Kaplan & Norton, 1996a & b)

The development of the strategy management system transformed the Balanced Scorecard from being an extended diagnostic system to an interactive system, defined by Bob Simons to have the following characteristics (Simons 1995a: 97):

1. Information generated by the system is an important and recurring agenda addressed by the highest levels of management
2. The interactive control system demands frequent and regular attention from operating managers at all levels of the organization.
3. Data generated by the system are interpreted and discussed in face-to-face meetings of superiors, subordinates, and peers.
4. The system is a catalyst for the continual challenge and debated of underlying data, assumptions, and actions plans.

9 Interview with Larry Brady in R. S. Kaplan and D.P. Norton, "Putting the Balanced Scorecard to Work," *Harvard Business Review* (September-October 1993): 147.

Simons' research indicated that CEOs selected an existing management system, such as the budget, the project management system, or the revenue system, and operated it interactively. Our development of the strategy map and Balanced Scorecard turned out, serendipitously, to offer managers the framework for a generic interactive system. Managers could now design a customized interactive system based on their strategy, and, following Brady's insight, use the strategy map and scorecard as the cornerstone of their management system for executing the strategy.[10]

For example of the system's interactivity, two senior executives at Mobil USM&R described how they used the Balanced Scorecard with their business unit and support unit managers. Bob McCool, CEO of the division stated:

> For a meeting with a BU manager, I have the manager plus representatives from various [support units], like supply, marketing, and convenience-stores. And we have a conversation. In the past we were a bunch of controllers sitting around talking about variances. Now we discuss what's gone right, what's gone wrong. What should we keep doing, what should we stop doing? What resources do we need to get back on track, not explaining a negative variance due to some volume mix.
>
> The process enables me to see how the NBU managers think, plan, and execute. I can see the gaps, and by understanding the manager's culture and mentality, I can develop customized programs to make him or her a better manager.

Brian Baker, executive vice president of Mobil USM&R talked about his meetings:

> I went into these reviews thinking they would be long and arduous. I was pleasantly surprised how simple they were. Managers came in prepared. They were paying attention to their scorecards and using them in a very productive way—to drive their organization hard to achieve the targets. How they weighted their measures spoke clearly about their priorities of relative importance up and down the four perspectives.
>
> Basically, there's no way I can understand and supervise all the activities that report to me. I need a device like the scorecard where the business unit managers are measuring their own performance. My job is to keep adjusting the light I shine on their strategy and implementation, to monitor and guide their journeys, and see whether there are any potential storms on the horizon that we should address.

These managers had never seen Simons' description and definition of an interactive system. But their natural leadership style was to operate their scorecard system to question, probe,

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10 Many academics, consultants, and managers, however, continue to think erroneously of the scorecard as a performance measurement system only. Their knowledge and acquaintance with the scorecard is probably based only on reading the original 1992 HBR article or the first half of the initial Balanced Scorecard book.

challenge, and coach about the strategy and its implementation, an ideal example of Simons' description of an interactive system.

After studying the successful implementations of Mobil USM&R and other early adopters we proposed the following five leadership and management processes for successful strategy execution, helping to create "the strategy-focused organization" (SFO) (Kaplan & Norton 2001):

1. Mobilize change through executive leadership
2. Translate the strategy
3. Align the organization to the strategy
4. Motivate employees to make strategy their everyday job
5. Govern to make strategy a continual process

This research completed the transformation of the Balanced Scorecard from a performance measurement system to an interactive management system for strategy execution.

Subsequent work, documented in additional books and *Harvard Business Review* articles, expanded upon this framework. Our third book, *Strategy Maps*, already mentioned, expanded upon Principle 2. Our fourth book, *Alignment*, expanded on Principle 3. We showed how strategy maps and scorecards could articulate the role for a corporate strategy that defined how to a collection of business units could create more value than if each unit operated autonomously, as a stand-alone company (Kaplan & Norton, 2006a&b). We discovered that all the various corporate strategies for enhancing the value of their business units could be represented using the four Balanced Scorecard perspectives, as shown in **Figure 3**.

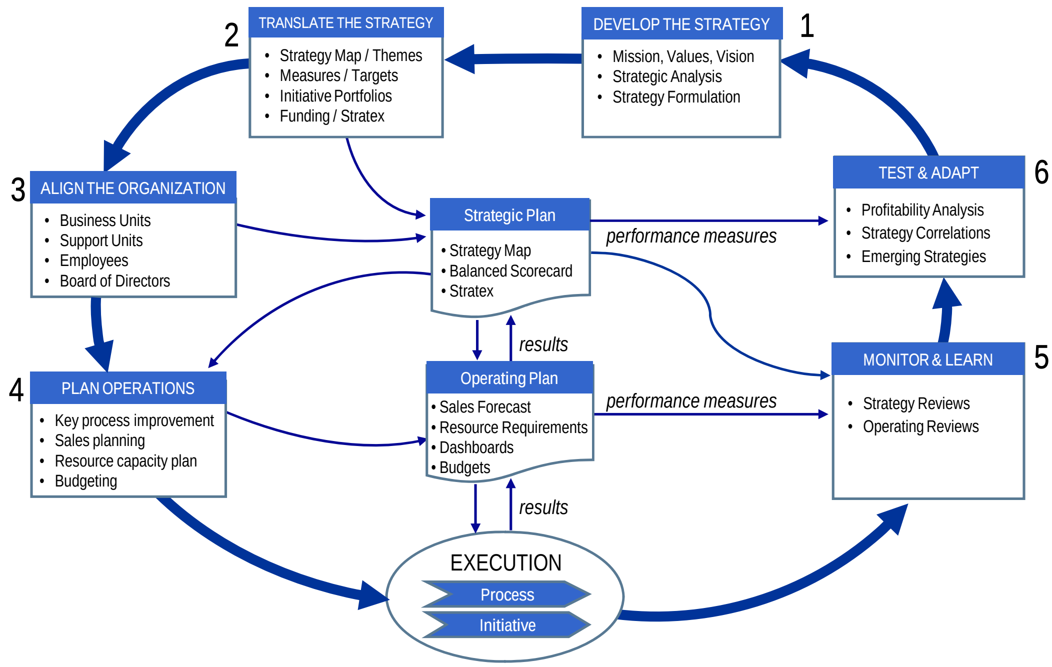
Figure 3 Sources of Enterprise Synergy

The Enterprise Scorecard	Sources of Enterprise Derived Value (Corporate Themes)
Financial Synergies "How can we increase the shareholder value of our SBU portfolio?"	❑ *Internal Capital Management* – Create synergy through effective management of internal capital & labor markets. ❑ *Corporate Brand* – Integrate a diverse set of businesses around a single brand, promoting common values or themes.
Customer Synergies "How can we share the customer Interface to increase total customer value?"	❑ *Cross-Selling* – Create value by cross-selling a broad range of products/services from several business units. ❑ *Common Value Proposition* – Create a consistent buying experience, conforming to corporate standards at multiple outlets.
Internal Process Synergies "How can we manage SBU processes to achieve economies of scale or value chain integration?'	❑ *Shared Services* – Create economies of scale by sharing the systems, facilities and personnel in critical support processes. ❑ *Value Chain Integration* – Create value by integrating contiguous processes in the industry value chain.
Learning & Growth Synergies "How can we develop and share our intangible assets?'	❑ *Intangible Assets* – Share a competency around the development of human, information and organization capital. ❑ *Strategic Themes* – Provide leadership in complex organizations through the management of strategic themes.

Our most recent work has focused on Principle 5, in which companies link strategy and operations (Kaplan & Norton, 2008a&b). **Figure 4** shows the architecture of a comprehensive six stage closed-loop management system that links strategic planning with operational execution.

1. Develop the strategy
2. Translate the strategy
3. Align the organization
4. Plan operations
5. Monitor and learn
6. Test and adapt the strategy

Figure 4 A Closed Loop Management System for Strategy Execution



In the sixth stage, managers use internal operational data and new external environmental and competitive data to test and update the strategy, which launches another loop around the integrated strategy and operational management system. This work integrates not only our prior work on strategy maps, alignment, and employee motivation, but also quality management, dashboards, time-driven activity-based costing for resource capacity planning and strategy feedback (Kaplan & Anderson, 2004, 2007), strategy development and formulation tools, and analytics for testing and adapting the strategy.

This most recent development is about much more than just the Balanced Scorecard. It embeds the original Balanced Scorecard framework as a component within a comprehensive management system that integrates strategy and operations. One can view the proposed management system as accomplishing the comprehensive framework advocated earlier by Herb Simon – for scorecarding, attention-directing, and problem-solving – and Robert Anthony, for strategic planning, management control and operational control. Rather than have them as separate activities, as suggested by Simon and Anthony, we now have the various activities for strategy development, planning, alignment, operational planning, operational control, and strategy control integrated within a closed-loop, comprehensive management system.

The integrated and comprehensive closed-loop management system has many moving parts and inter-relationships, and requires simultaneous coordination among all organizational line and staff units. Existing processes that today are run by different parts of the organization – such as budgeting by finance, personal goals and communications by human resources, and process management by operations – must be modified and coordinated to create strategic alignment. They must work as a system instead of a set of uncoordinated sub-systems as they do today. In addition, we have proposed some entirely new processes – such as creating strategy maps and scorecards that align organizational units and employees to the strategy. Because these processes are new to most organizations, they have no natural home within the existing structure. Clearly, organizations face a complex task to implement such a complex, inter-related system.

We have identified the need for a new organizational function, which we call the Office of Strategy Management (OSM), to be the process owner of the strategy execution system and its component processes (Kaplan & Norton 2005). The OSM has ownership for the new processes that translate and cascade the strategy, link it to operations, and organize the strategy review and strategy testing and adapting meetings. It also integrates and coordinates activities that align strategy and operations across functions and business units. The OSM, analogous to a military general's chief-of-staff keeps all the diverse organizational players ─ executive team, business units, regional units, support units (finance, human resources, information technology), departments, and, ultimately, the employees ─ aligned with each other, operating independently, when appropriate, but also coming together, as needed, to execute the enterprise's strategy.

6. Future Opportunities

This article has documented the precursors of the Balanced Scorecard and its continued evolution, from its introduction in 1992 to recent developments in 2008, the time at which this article was written. Intensive and continual collaboration with innovating companies, public sector agencies, and nonprofit organizations have informed the enhancements and capabilities of the original Balanced Scorecard. Among these advances are the following:

- Strategy maps of strategic objectives
- Extending the concept to nonprofit and public sector enterprises

- Measurement of strategic readiness of intangible assets
- Role for executive leadership
- Creating synergies through alignment of business and support units to corporate strategy
- Using communication to create intrinsic motivation
- Deploying extrinsic motivation by aligning employees' personal objectives and compensation to strategic objectives
- Linking strategy and operations in a new closed-loop management system
- Creating the office of strategy management

It's not easy to respond when questioned about what happens next. While each of these advances was a logical extension of previous work, each presented itself incrementally and opportunistically, not as part of a planned evolution of the concept over a 15 year period. While acknowledging a cloudy crystal ball, I can see several big opportunities for future work.

First, the early adopters of the BSC – Rockwater, FMC, Mobil, Chemical Bank, Cigna P&C, AT&T Canada, Wells Fargo Online Services, and City of Charlotte – had superb leaders. Initially, perhaps, we took such leadership for granted. Subsequent experience revealed that when the Balanced Scorecard failed in organizations, we could usually trace the roots of failure back to lack of executive leadership, not to any particular inherent design flaw in strategy maps, scorecards, or the four other strategy-focused organization principles. The failures occurred when staff groups or functional officers introduced the scorecard with the acquiescence but not the leadership and commitment of the CEO of the business unit. And the purpose for introducing the Balanced Scorecard was not for effective strategy execution, but for more tactical reasons, such as to change the compensation system, to reinforce a quality management system, or to change the reporting system to give managers more access to information about their operations. All of these goals are laudable but none, by itself, can transform and align an organization for effective strategy execution, the principal deliverable, as it turned out, for Balanced Scorecard implementations.

Future research studies of BSC implementations could certainly benefit from measuring organizational leadership in each implementation and assessing this factor's role in creating success. Several authors have done limited testing about the environments in which the Balanced Scorecard has succeeded or failed. Most of these studies were ad hoc correlations of nonfinancial and financial variables. Few of the studies were informed by the concepts described in our writings on strategy-focused organization principles and the most recent work on integration of strategic planning and operational execution. The empirical evidence that Norton and I have seen and documented over the past 15 years identifies *leadership* as the most important variable explaining success or failure. To state a bold hypothesis, leadership may be both necessary and sufficient for success. It is necessary since without it, the Balanced Scorecard will be just another ad hoc reporting system, and the gains from embedding the Balanced Scorecard in a system for effective strategy execution will not be realized. Leadership is required to translate strategy into the linked strategic objectives on a strategy map and then to use the map and the accompanying scorecard *interactively* as described in this chapter. The more challenging claim is that it is also sufficient. This hypothesis emerges from the documented best practices, drawn from hundreds of successful implementations, on how to build and operate the new management system for strategy execution. Managers can apply this body of knowledge, which is referenced in this article, to implement the four strategy-focused organization principles other than leadership. But none of the four principles can be effectively mobilized and sustained without leadership at the top. Of course, such a strong claim about both necessity and sufficiency needs to be tested through careful research designs and instruments.

Research in leadership would start with measurement; there could be multiple forms of effective leadership, but some aspects may be necessary or common across all leadership styles. Once leadership can be measured validly, then cross-sectional or longitudinal research can be performed to see its influence on explaining variation in the results delivered from following the five SFO principles.

Second, the emerging literature and practice on enterprise risk management needs to be more formally embedded in the strategy map and Balanced Scorecard. Many companies, especially financial services companies, have already specified risk management objectives in the scorecard's financial and process objectives. But these additions have been incremental and not part of an integrated risk management framework. Our generic strategy map template (see Figure 2) emphasizes two primary financial sub-strategies, revenue growth and productivity, as the drivers of sustainable shareholder value creation. Surely, risk management must be introduced as a third pillar for financial performance, and perhaps an entirely new set of risk management processes should be included within the process perspective. Given the intense focus of companies around the world to improve their measurement and management of risk, we should expect important advances, over the next five years, to embed risk management objectives more centrally into the strategy execution framework.

Third, strategy maps still represent a highly-aggregated view of causal relationships among strategic objectives. In order to make strategy maps more visually appealing to managers and employees, we have simplified the causal relationships assumed within the strategy map (one might even describe the generic strategy map as a "dumbed-down" representation of causal linkages). Norton and I, both trained as electrical engineers, have been aware from the outset that systems dynamics techniques could help produce a more detailed model that links both strategic and operational objectives in a more elaborate mapping exercise. A detailed systems dynamics model would incorporate causal linkages that have estimates of magnitude and time delay, as well as more complex feedback loops than are presently visualized in the generic strategy map. For an example of such a quantified linkage, analysts could estimate the percentage improvement in a lagging indicator that would be expected from, say, a 1% improvement in a leading indicator. The analysts would also estimate the time delay between a 1% improvement in a leading indicator and the expected response in a lagging indicator. And the causal linkages need not be uni-dimensional. The model could include multiple leading indicators and impacts that can be a combination of linear, multiplicative, or even Boolean (no impact if the improvement is less than a given amount; a jump in impact once a threshold level of improvement has been achieved).

The statistical and modeling capabilities for constructing models of detailed causal relationships already exists. And many companies, particularly those operating hundreds or thousands of relatively similar decentralized units, generate sufficient data each month to estimate even complex models. The shortage seems to be how to marry analytic capabilities with companies that generate sufficient data and have a senior management team capable of understanding and using the dynamic, causal models effectively to guide their strategies and operations.

Thus, while much has been learned over the past 15 years, much interesting research can still be done. And with many private, public sector, and nonprofit enterprises around the world implementing new strategy execution systems based on the Balanced Scorecard framework, the opportunities for informed empirical research are great.

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The scorecard tracks the key elements of a company's strategy – from continuous improvement and partnerships to teamwork and global scale.

The Balanced Scorecard – Measures That Drive Performance

by Robert S. Kaplan and David P. Norton

What you measure is what you get. Senior executives understand that their organization's measurement system strongly affects the behavior of managers and employees. Executives also understand that traditional financial accounting measures like return-on-investment and earnings-per-share can give misleading signals for continuous improvement and innovation – activities today's competitive environment demands. The traditional financial performance measures worked well for the industrial era, but they are out of step with the skills and competencies companies are trying to master today.

> The balanced scorecard is like the dials in an airplane cockpit: it gives managers complex information at a glance.

As managers and academic researchers have tried to remedy the inadequacies of current performance measurement systems, some have focused on making financial measures more relevant. Others have said, "Forget the financial measures. Improve operational measures like cycle time and defect rates; the financial results will follow." But managers should not have to choose between financial and operational measures. In observing and working with many companies, we have found that senior executives do not rely on one set of measures to the exclusion of the other. They realize that no single measure can provide a clear performance target or focus attention on the critical areas of the business. Managers want a balanced presentation of both financial and operational measures.

During a year-long research project with 12 companies at the leading edge of performance measurement, we devised a "balanced scorecard" – a set of measures that gives top managers a fast but comprehensive view of the business. The balanced scorecard includes financial measures that tell the results of actions already taken. And it complements the financial measures with operational measures on customer satisfaction, internal processes, and the organization's innovation and improvement activities – operational measures that are the drivers of future financial performance.

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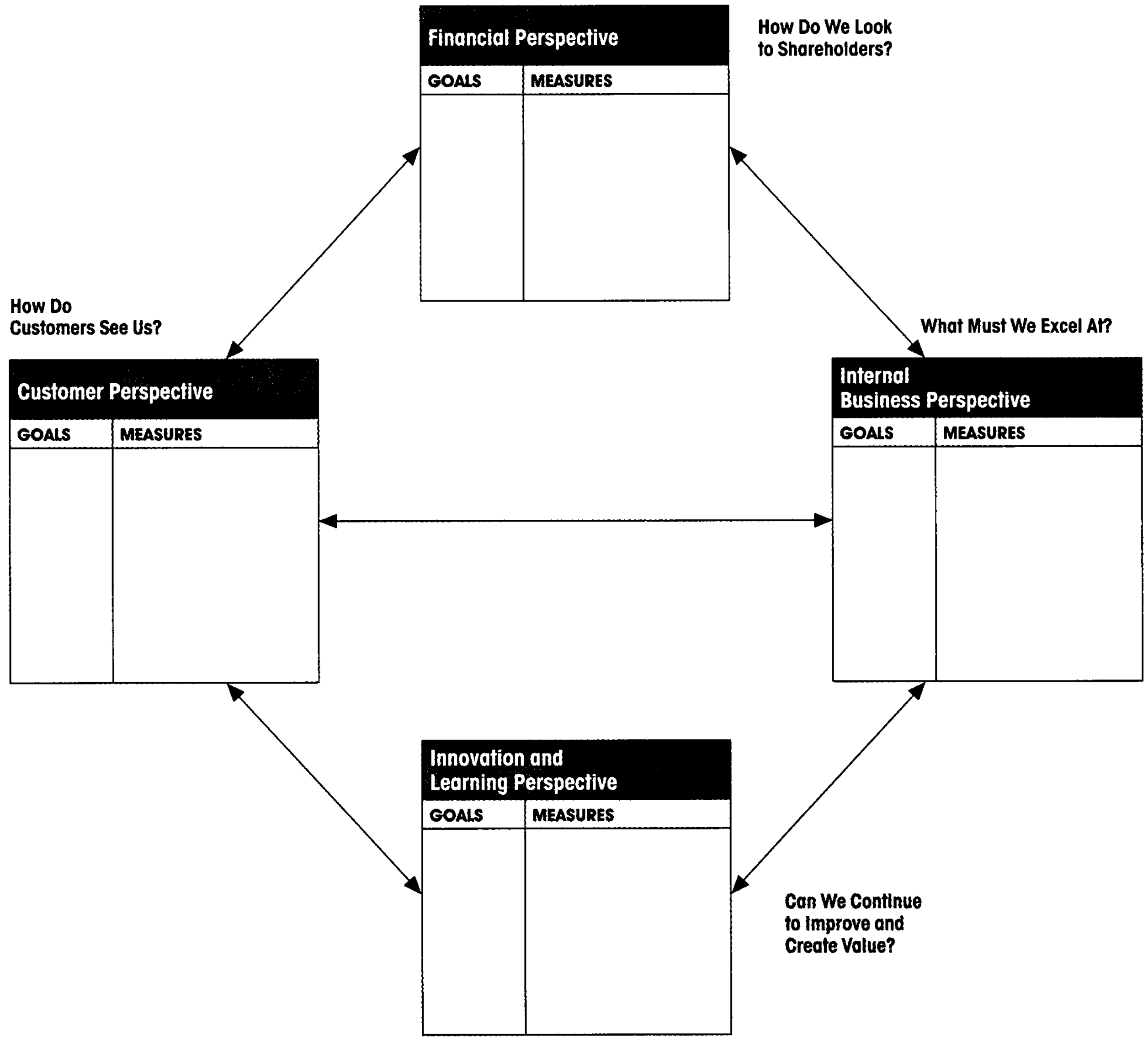
Think of the balanced scorecard as the dials and indicators in an airplane cockpit. For the complex task of navigating and flying an airplane, pilots need detailed information about many aspects of the flight. They need information on fuel, air speed, altitude, bearing, destination, and other indicators that summarize the current and predicted environment. Reliance on one instrument can be fatal. Similarly, the complexity of managing an organization today requires that managers be able to view performance in several areas simultaneously.

The balanced scorecard allows managers to look at the business from four important perspectives. (See the exhibit "The Balanced Scorecard Links Performance Measures.") It provides answers to four basic questions:

- ☐ How do customers see us? (customer perspective)
- ☐ What must we excel at? (internal perspective)
- ☐ Can we continue to improve and create value? (innovation and learning perspective)
- ☐ How do we look to shareholders? (financial perspective)

While giving senior managers information from four different perspectives, the balanced scorecard minimizes information overload by limiting the number of measures used. Companies rarely suffer

The Balanced Scorecard Links Performance Measures



from having too few measures. More commonly, they keep adding new measures whenever an employee or a consultant makes a worthwhile suggestion. One manager described the proliferation of new measures at his company as its "kill another tree program." The balanced scorecard forces managers to focus on the handful of measures that are most critical.

Several companies have already adopted the balanced scorecard. Their early experiences using the scorecard have demonstrated that it meets several managerial needs. First, the scorecard brings together, in a single management report, many of the seemingly disparate elements of a company's competitive agenda: becoming customer oriented, shortening response time, improving quality, emphasizing teamwork, reducing new product launch times, and managing for the long term.

Second, the scorecard guards against suboptimization. By forcing senior managers to consider all the important operational measures together, the balanced scorecard lets them see whether improvement in one area may have been achieved at the expense of another. Even the best objective can be achieved badly. Companies can reduce time to market, for example, in two very different ways: by improving the management of new product introductions or by releasing only products that are incrementally different from existing products. Spending on setups can be cut either by reducing setup times or by increasing batch sizes. Similarly, production output and first-pass yields can rise, but the increases may be due to a shift in the product mix to more standard, easy-to-produce but lower-margin products.

We will illustrate how companies can create their own balanced scorecard with the experiences of one semiconductor company – let's call it Electronic Circuits Inc. ECI saw the scorecard as a way to clarify, simplify, and then operationalize the vision at the top of the organization. The ECI scorecard was designed to focus the attention of its top executives on a short list of critical indicators of current and future performance.

Customer Perspective: How Do Customers See Us?

Many companies today have a corporate mission that focuses on the customer. "To be number one in delivering value to customers" is a typical mission statement. How a company is performing from its customers' perspective has become, therefore, a priority for top management. The balanced scorecard demands that managers translate their general mission statement on customer service into specific measures that reflect the factors that really matter to customers.

Customers' concerns tend to fall into four categories: time, quality, performance and service, and cost. Lead time measures the time required for the company to meet its customers' needs. For existing products, lead time can be measured from the time the company receives an order to the time it actually delivers the product or service to the customer. For new products, lead time represents the time to market, or how long it takes to bring a new product from the product definition stage to the start of shipments. Quality measures the defect level of incoming products as perceived and measured by the customer. Quality could also measure on-time delivery, the accuracy of the company's delivery forecasts. The combination of performance and service measures how the company's products or services contribute to creating value for its customers.

> The balanced scorecard shows *how* results are achieved: Did the cost of setups fall because of shorter setup times or bigger batch sizes?

To put the balanced scorecard to work, companies should articulate goals for time, quality, and performance and service and then translate these goals into specific measures. Senior managers at ECI, for example, established general goals for customer performance: get standard products to market sooner, improve customers' time to market, become customers' supplier of choice through partnerships with them, and develop innovative products tailored to customer needs. The managers translated these general goals into four specific goals and identified an appropriate measure for each. (See the exhibit "ECI's Balanced Scorecard.")

To track the specific goal of providing a continuous stream of attractive solutions, ECI measured the percent of sales from new products and the percent of sales from proprietary products. That information was available internally. But certain other measures forced the company to get data from outside. To assess whether the company was achieving its goal of providing reliable, responsive supply, ECI turned to its customers. When it found that each customer defined "reliable, responsive supply" differently, ECI

Other Measures for the Customer's Perspective

A computer manufacturer wanted to be the competitive leader in customer satisfaction, so it measured competitive rankings. The company got the rankings through an outside organization hired to talk directly with customers. The company also wanted to do a better job of solving customers' problems by creating more partnerships with other suppliers. It measured the percentage of revenue from third-party relationships.

The customers of a producer of very expensive medical equipment demanded high reliability. The company developed two customer-based metrics for its operations: equipment up-time percentage and mean-time response to a service call.

A semiconductor company asked each major customer to rank the company against comparable suppliers on efforts to improve quality, delivery time, and price performance. When the manufacturer discovered that it ranked in the middle, managers made improvements that moved the company to the top of customers' rankings.

created a database of the factors as defined by each of its major customers. The shift to external measures of performance with customers led ECI to redefine "on time" so it matched customers' expectations. Some customers defined "on-time" as any shipment that arrived within five days of scheduled delivery; others used a nine-day window. ECI itself had been using a seven-day window, which meant that the company was not satisfying some of its customers and overachieving at others. ECI also asked its top ten customers to rank the company as a supplier overall.

Depending on customers' evaluations to define some of a company's performance measures forces that company to view its performance through customers' eyes. Some companies hire third parties to perform anonymous customer surveys, resulting in a customer-driven report card. The J.D. Powers quality survey, for example, has become the standard of performance for the automobile industry, while the Department of Transportation's measurement of on-time arrivals and lost baggage provides external standards for airlines. Benchmarking procedures are yet another technique companies use to compare their performance against competitors' best practice. Many companies have introduced "best of breed" comparison programs: the company looks to one industry to find, say, the best distribution system, to another industry for the lowest cost payroll process, and then forms a composite of those best practices to set objectives for its own performance.

In addition to measures of time, quality, and performance and service, companies must remain sensitive to the cost of their products. But customers see price as only one component of the cost they incur when dealing with their suppliers. Other supplier-driven costs range from ordering, scheduling delivery, and paying for the materials; to receiving, inspecting, handling, and storing the materials; to the scrap, rework, and obsolescence caused by the materials; and schedule disruptions (expediting and value of lost output) from incorrect deliveries. An excellent supplier may charge a higher unit price for products than other vendors but nonetheless be a lower cost supplier because it can deliver defect-free products in exactly the right quantities at exactly the right time directly to the production process and can minimize, through electronic data interchange, the administrative hassles of ordering, invoicing, and paying for materials.

Internal Business Perspective: What Must We Excel at?

Customer-based measures are important, but they must be translated into measures of what the company must do internally to meet its customers' expectations. After all, excellent customer performance derives from processes, decisions, and actions occurring throughout an organization. Managers need to focus on those critical internal operations that enable them to satisfy customer needs. The second part of the balanced scorecard gives managers that internal perspective.

The internal measures for the balanced scorecard should stem from the business processes that have the greatest impact on customer satisfaction – factors that affect cycle time, quality, employee skills, and productivity, for example. Companies should also attempt to identify and measure their company's core competencies, the critical technologies needed to ensure continued market leadership. Companies should decide what processes and competencies they must excel at and specify measures for each.

Managers at ECI determined that submicron technology capability was critical to its market position. They also decided that they had to focus on manufacturing excellence, design productivity, and new product introduction. The company developed operational measures for each of these four internal business goals.

To achieve goals on cycle time, quality, productivity, and cost, managers must devise measures that are influenced by employees' actions. Since much of the action takes place at the department and workstation levels, managers need to decompose overall cycle time, quality, product, and cost measures to local levels. That way, the measures link top management's judgment about key internal processes and competencies to the actions taken by individuals that affect overall corporate objectives. This linkage ensures that employees at lower levels in the organization have clear targets for actions, decisions, and improvement activities that will contribute to the company's overall mission.

Information systems play an invaluable role in helping managers disaggregate the summary measures. When an unexpected signal appears on the balanced scorecard, executives can query their information system to find the source of the trouble. If the aggregate measure for on-time delivery is poor, for example, executives with a good information system can quickly look behind the aggregate measure until they can identify late deliveries, day by day, by a particular plant to an individual customer.

If the information system is unresponsive, however, it can be the Achilles' heel of performance measurement. Managers at ECI are currently limited by the absence of such an operational information system. Their greatest concern is that the scorecard information is not timely; reports are generally a week behind the company's routine management meetings, and the measures have yet to be linked to measures for managers and employees at lower levels of the organization. The company is in the process of developing a more responsive information system to eliminate this constraint.

Other Measures for the Internal Business Perspective

One company recognized that the success of its TQM program depended on all its employees internalizing and acting on the program's messages. The company performed a monthly survey of 600 randomly selected employees to determine if they were aware of TQM, had changed their behavior because of it, believed the outcome was favorable, or had become missionaries to others.

Hewlett-Packard uses a metric called breakeven time (BET) to measure the effectiveness of its product development cycle. BET measures the time required for all the accumulated expenses in the product and process development cycle (including equipment acquisition) to be recovered by the product's contribution margin (the selling price less manufacturing, delivery, and selling expenses).

A major office products manufacturer, wanting to respond rapidly to changes in the marketplace, set out to reduce cycle time by 50%. Lower levels of the organization aimed to radically cut the times required to process customer orders, order and receive materials from suppliers, move materials and products between plants, produce and assemble products, and deliver products to customers.

Innovation and Learning Perspective: Can We Continue to Improve and Create Value?

The customer-based and internal business process measures on the balanced scorecard identify the parameters that the company considers most important for competitive success. But the targets for success keep changing. Intense global competition requires that companies make continual improvements to their *existing* products and processes and have the ability to introduce entirely new products with expanded capabilities.

A company's ability to innovate, improve, and learn ties directly to the company's value. That is, only through the ability to launch new products, create more value for customers, and improve operating efficiencies continually can a company penetrate new markets and increase revenues and margins – in short, grow and thereby increase shareholder value.

ECI's innovation measures focus on the company's ability to develop and introduce standard products rapidly, products that the company expects will form the bulk of its future sales. Its manufacturing improvement measure focuses on new products; the goal is to achieve stability in the manufacturing of new products rather than to improve manufacturing of existing products. Like many other companies, ECI uses the percent of sales from new products as one of its innovation and improvement measures. If sales from new products is trending downward, managers can explore whether problems have arisen in new product design or new product introduction.

In addition to measures on product and process innovation, some companies overlay specific improvement goals for their existing processes. For example, Analog Devices, a Massachusetts-based manufacturer of specialized semiconductors, expects man-

ECI's Balanced Business Scorecard

Financial Perspective

GOALS	MEASURES
Survive	Cash flow
Succeed	Quarterly sales growth and operating income by division
Prosper	Increased market share and ROE

Customer Perspective

GOALS	MEASURES
New products	Percent of sales from new products
	Percent of sales from proprietary products
Responsive supply	On-time delivery (defined by customer)
Preferred supplier	Share of key accounts' purchases
	Ranking by key accounts
Customer partnership	Number of cooperative engineering efforts

Internal Business Perspective

GOALS	MEASURES
Technology capability	Manufacturing geometry vs. competition
Manufacturing excellence	Cycle time Unit cost Yield
Design productivity	Silicon efficiency Engineering efficiency
New product introduction	Actual introduction schedule vs. plan

Innovation and Learning Perspective

GOALS	MEASURES
Technology leadership	Time to develop next generation
Manufacturing learning	Process time to maturity
Product focus	Percent of products that equal 80% sales
Time to market	New product introduction vs. competition

agers to improve their customer and internal business process performance continuously. The company estimates specific rates of improvement for on-time delivery, cycle time, defect rate, and yield.

Other companies, like Milliken & Co., require that managers make improvements within a specific time period. Milliken did not want its "associates" (Milliken's word for employees) to rest on their laurels after winning the Baldrige Award. Chairman and CEO Roger Milliken asked each plant to implement a "ten-four" improvement program: measures of process defects, missed deliveries, and scrap were to be reduced by a factor of ten over the next four years. These targets emphasize the role for continuous improvement in customer satisfaction and internal business processes.

Financial Perspective: How Do We Look to Shareholders?

Financial performance measures indicate whether the company's strategy, implementation, and execution are contributing to bottom-line improvement. Typical financial goals have to do with profitability, growth, and shareholder value. ECI stated its financial goals simply: to survive, to succeed, and to prosper. Survival was measured by cash flow, success by quarterly sales growth and operating income by division, and prosperity by increased market share by segment and return on equity.

But given today's business environment, should senior managers even look at the business from a financial perspective? Should they pay attention to short-term financial measures like quarterly sales and operating income? Many have criticized financial measures because of their well-documented inadequacies, their backward-looking focus, and their inability to reflect contemporary value-creating actions. Shareholder value analysis (SVA), which forecasts future cash flows and discounts them back to a rough estimate of current value, is an attempt to make financial analysis more forward looking. But SVA still is based on cash flow rather than on the activities and processes that drive cash flow.

Some critics go much further in their indictment of financial measures. They argue that the terms of competition have changed and that traditional financial measures do not improve customer satisfaction, quality, cycle time, and employee motivation. In their view, financial performance is the result of operational actions, and financial success should be the logical consequence of doing the fundamentals well. In other words, companies should stop navigating by financial measures. By making fundamental improvements in their operations, the financial numbers will take care of themselves, the argument goes.

Assertions that financial measures are unnecessary are incorrect for at least two reasons. A well-designed financial control system can actually enhance rather than inhibit an organization's total quality management program. (See the insert, "How One Company Used a Daily Financial Report to Improve Quality.") More important, however, the alleged linkage between improved operating performance and financial success is actually quite tenuous and uncertain. Let us demonstrate rather than argue this point.

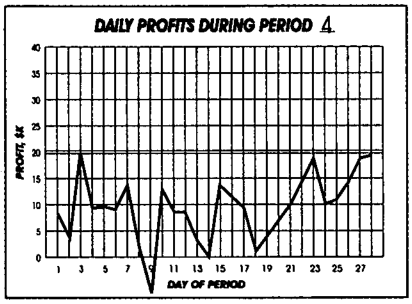
Over the three-year period between 1987 and 1990, a NYSE electronics company made an order-of-magnitude improvement in quality and on-time delivery performance. Outgoing defect rate dropped from 500 parts per million to 50, on-time delivery improved from 70% to 96%, and yield jumped from 26% to 51%. Did these breakthrough improvements in quality, productivity, and customer service provide substantial benefits to the company? Unfortunately not. During the same three-year period, the company's financial results showed little improvement, and its stock price plummeted to one-third of its July 1987 value. The considerable improvements in manufacturing capabilities had not been translated into increased profitability. Slow releases of new products and a failure to expand marketing to new and perhaps more demanding customers prevented the company from realizing the benefits of its manufacturing achievements. The operational achievements were real, but the company had failed to capitalize on them.

The disparity between improved operational performance and disappointing financial measures creates frustration for senior executives. This frustration is often vented at nameless Wall Street analysts who allegedly cannot see past quarterly blips in financial performance to the underlying long-term values these executives sincerely believe they are creating in their organizations. But the hard truth is that if improved performance fails to be reflected in the bottom line, executives should reexamine the basic assumptions of their strategy and mission. Not all long-term strategies are profitable strategies.

Measures of customer satisfaction, internal business performance, and innovation and improvement are derived from the company's particular view of the world and its perspective on key success factors. But that view is not necessarily correct. Even an excellent set of balanced scorecard measures does not guarantee a winning strategy. The balanced score-

How One Company Used a Daily Financial Report to Improve Quality*

In the 1980s, a chemicals company became committed to a total quality management program and began to make extensive measurements of employee participation, statistical process control, and key quality indicators. Using computerized controls and remote data entry systems, the plant monitored more than 30,000 observations of its production processes every four hours. The department managers and operating personnel who now had access to massive amounts of real-time operational data found their monthly financial reports to be irrelevant.



But one enterprising department manager saw things differently. He created a daily income statement. Each day, he estimated the value of the output from the production process using estimated market prices and subtracted the expenses of raw materials, energy, and capital consumed in the production process. To approximate the cost of producing out-of-conformance product, he cut the revenues from off-spec output by 50% to 100%.

The daily financial report gave operators powerful feedback and motivation and guided their quality and productivity efforts. The department head understood that it is not always possible to improve quality, reduce energy consumption, and increase throughput simultaneously; tradeoffs are usually necessary. He wanted the daily financial statement to guide those tradeoffs. The difference between the input consumed and output produced indicated the success or failure of the employees' efforts on the previous day. The operators were empowered to make decisions that might improve quality, increase productivity, and reduce consumption of energy and materials.

That feedback and empowerment had visible results. When, for example, a hydrogen compressor failed, a supervisor on the midnight shift ordered an emergency repair crew into action. Previously, such a failure of a noncritical component would have been reported in the shift log, where the department manager arriving for work the following morning would have to discover it. The midnight shift supervisor knew the cost of losing the hydrogen gas and made the decision that the cost of expediting the repairs would be repaid several times over by the output produced by having the compressor back on line before morning.

The department proceeded to set quality and output records. Over time, the department manager became concerned that employees would lose interest in continually improving operations. He tightened the parameters for in-spec production and reset the prices to reflect a 25% premium for output containing only negligible fractions of impurities. The operators continued to improve the production process.

The success of the daily financial report hinged on the manager's ability to establish a financial penalty for what had previously been an intangible variable: the quality of output. With this innovation, it was easy to see where process improvements and capital investments could generate the highest returns.

*Source: "Texas Eastman Company," by Robert S. Kaplan, Harvard Business School Case No. 9-190-039.

card can only translate a company's strategy into specific measurable objectives. A failure to convert improved operational performance, as measured in the scorecard, into improved financial performance should send executives back to their drawing boards to rethink the company's strategy or its implementation plans.

As one example, disappointing financial measures sometimes occur because companies don't follow up their operational improvements with another round of actions. Quality and cycle-time improvements can create excess capacity. Managers should be prepared to either put the excess capacity to work or else get rid of it. The excess capacity must be either used by boosting revenues or eliminated by reducing expenses if operational improvements are to be brought down to the bottom line.

As companies improve their quality and response time, they eliminate the need to build, inspect, and rework out-of-conformance products or to reschedule and expedite delayed orders. Eliminating these tasks means that some of the people who perform them are no longer needed. Companies are understandably reluctant to lay off employees, especially since the employees may have been the source of the ideas that produced the higher quality and reduced cycle time. Layoffs are a poor reward for past improvement and can damage the morale of remaining workers, curtailing further improvement. But companies will not realize all the financial benefits of their improvements until their employees and facilities are working to capacity – or the companies confront the pain of downsizing to eliminate the expenses of the newly created excess capacity.

If executives fully understood the consequences of their quality and cycle-time improvement programs, they might be more aggressive about using the newly created capacity. To capitalize on this self-created new capacity, however, companies must expand sales to existing customers, market existing products to entirely new customers (who are now accessible because of the improved quality and delivery performance), and increase the flow of new products to the market. These actions can generate added revenues with only modest increases in operating expenses. If marketing and sales and R&D do not generate the increased volume, the operating improvements will stand as excess capacity, redundancy, and untapped capabilities. Periodic financial statements remind executives that improved quality, response time, productivity, or new products benefit the company only when they are translated into improved sales and market share, reduced operating expenses, or higher asset turnover.

Ideally, companies should specify how improvements in quality, cycle time, quoted lead times, delivery, and new product introduction will lead to higher market share, operating margins, and asset turnover or to reduced operating expenses. The challenge is to learn how to make such explicit linkage between operations and finance. Exploring the complex dynamics will likely require simulation and cost modeling.

Measures That Move Companies Forward

As companies have applied the balanced scorecard, we have begun to recognize that the scorecard represents a fundamental change in the underlying assumptions about performance measurement. As the controllers and finance vice presidents involved in the research project took the concept back to their organizations, the project participants found that they could not implement the balanced scorecard without the involvement of the senior managers who have the most complete picture of the company's vision and priorities. This was revealing because most existing performance measurement systems have been designed and overseen by financial experts. Rarely do controllers need to have senior managers so heavily involved.

> The balanced scorecard puts strategy – not control – at the center.

Probably because traditional measurement systems have sprung from the finance function, the systems have a control bias. That is, traditional performance measurement systems specify the particular actions they want employees to take and then measure to see whether the employees have in fact taken those actions. In that way, the systems try to control behavior. Such measurement systems fit with the engineering mentality of the Industrial Age.

The balanced scorecard, on the other hand, is well suited to the kind of organization many companies are trying to become. The scorecard puts strategy and vision, not control, at the center. It establishes goals but assumes that people will adopt whatever behaviors and take whatever actions are necessary to arrive at those goals. The measures are designed to pull people toward the overall vision. Senior managers may know what the end result should be, but they cannot tell employees exactly how to achieve that result, if only because the conditions in which employees operate are constantly changing.

This new approach to performance measurement is consistent with the initiatives under way in many companies: cross-functional integration, customer-supplier partnerships, global scale, continuous improvement, and team rather than individual accountability. By combining the financial, customer, internal process and innovation, and organizational learning perspectives, the balanced scorecard helps managers understand, at least implicitly, many interrelationships. This understanding can help managers transcend traditional notions about functional barriers and ultimately lead to improved decision making and problem solving. The balanced scorecard keeps companies looking – and moving – forward instead of backward.

Reprint 92105

BOMA INTERROGATORY 27

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p48 (Elenchus)***

(a) Please discuss each of the metrics which address Bulk Power System Reliability on p48. Please describe each of the criteria, and its purpose, and whether it would be appropriate for use as a metric for the IESO.

(b) Please do the same for metrics in the boxes on p49, addressing Coordinated Wholesale Power Markets, and Organizational Effectiveness.

RESPONSE

The IESO does not believe any of the criteria would be appropriate for use as a metric for the IESO.

Please note that responses below were provided by Elenchus.

(a) Please refer to Table 1.

Table 1. Bulk Power System Reliability[1]

Metric	Criteria	Purpose
Dispatch Operations	**Compliance with CPS-1 and CPS-2** • Each Balancing Authority (BA) shall achieve a minimum compliance of 100% for Control Performance Standard 1 (CPS1) (rolling annual average) and a minimum compliance of 90% for CPS2 (monthly average). • An alternative method of measurement is using the BAAL (Balancing Authority ACE Limit). This standard requires the	For helping maintain the steady-state frequency in each Balancing Authority (BA)'s interconnection within defined limits.

[1] All information describing criteria and purpose has been extracted from the 2010 ISO/RTO Metrics Report, available at: http://www.isorto.org/Documents/Report/2010IRCMetricsReport_2005-2009.pdf

Metric	Criteria	Purpose
	balancing authority to demonstrate real-time monitoring of ACE and interconnection frequency against associated limits and to balance its resources and demands in real-time so that its ACE does not exceed the BAALs for a time greater than 30 minutes. In addition, this standard limits the recovery period to no more than 30 minutes for a single event. **Transmission Load Relief or Unscheduled Flow Relief Events** • Illustrates the Transmission Loading Reliefs (TLR) level 3 events or greater and Unscheduled Flow Relief (UFR) activity for each ISO/RTO. **Energy Management System Availability** Measures the percentage of minutes each year that the ISO's/RTO's Energy Management System (EMS) was operationally available for use by the ISO's/RTO's dispatch operations staff.	
Load Forecast Accuracy	Generally speaking, higher forecasting accuracy is good as it means that the actual load was closer to the forecast load. Mean Absolute Percentage Error (MAPE) is commonly used in quantitative forecasting methods because it produces a measure of relative overall precision; the lower the MAPE, the more precise the forecast.	Accurately forecasting load is critical because the forecast drives the commitment of generation and/or demand response for future periods. Inaccurate forecasting can manifest itself in either reliability problems (due to

Metric	Criteria	Purpose
		under-commitment of resources) or in additional costs (due to either over-commitment of resources or inefficient commitment of short lead-time resources).
Wind Forecasting Accuracy	Quantify the percentage accuracy of the actual wind generation availability compared with the forecasted wind generation availability as of the close of the prior day's day-ahead market.	The ability to accurately forecast variable energy resources output, therefore, becomes critical to manage uncertainty and maintain bulk power system reliability by facilitating the timely commitment and dispatch of sufficient supplemental resources.
Unscheduled Flows	The absolute value of the total terawatt hours of unscheduled flows for each ISO/RTO and the absolute value of the total terawatt hours of unscheduled flows for each ISO/RTO as a percentage of total terawatt hours of flows.	Unscheduled flows contributing to actual power flow in excess of the system operating limit adversely impacts scheduled use of the grid, resulting in the need to curtail schedules

Metric	Criteria	Purpose
		on the specific intertie and return actual path flows within the system operating limit.
Transmission Outage Coordination	Measure how promptly ISOs/RTOs are receiving planned transmission outage requests, how effective each ISO/RTO is at processing transmission outage requests, how often each ISO/RTO cancels previously-approved transmission outages, and the level of unplanned transmission outages in each ISO/RTO region.	The ISO/RTO studies the planned transmission outage to determine whether such an outage request would create any reliability concerns. Even after approving a transmission outage request, an ISO/RTO can cancel a planned transmission outage if system conditions have changed such that an outage may create a reliability issue.
Transmission Planning	ISO/RTO's take a long-term (generally 10 years or more) analytical approach to bulk power system planning with broad stakeholder participation to address reliability and economic benefit at intra- and inter-regional levels	Provides an indication of the progress made to address reliability needs or economic opportunities early enough, to engage a broad set of stakeholders, and to successfully

Metric	Criteria	Purpose
		carry the projects to completion.
Generation Interconnection	**Average Generation Interconnection Request Processing Time** • This metric is calculated as the simple average of the number of days between when a generation interconnection application is received and when the final application response is provided to the requestor - for all responses provided during the calendar year. • Generally speaking, a shorter average study period is preferred. **Planned and Actual Reserve Margins** • This metric compares the planned reserve margin to the actual reserve margin for each region. • Generally speaking, an actual reserve margin at or slightly above the planned reserve margin is desired. **Percentage of Generation Outages Cancelled by ISO/RTO** • This measure reflects the percentage of planned generation outages reported to each ISO/RTO that were cancelled by that ISO/RTO. **Generation Reliability Must Run Contracts** • The information under this topic reflects the number of generating units and the nameplate generating capacity of any generation units under reliability must run (RMR) contracts.	To facilitate unbiased and open access to all potential electric grid users.
Interconnection/Transmission Service Requests	Reflects the number of interconnection and transmission service requests received and completed as well as the	• To assess the potential transmission

Metric	Criteria	Purpose
	average aging of incomplete interconnection and transmission service requests and the average time the ISO/RTO took to complete each study.	system upgrades required for the incremental generation capacity to interconnect reliably to the respective ISO's/RTO's transmission system. • To review and approve or reject, based on the anticipated impact to reliability, requests for both transmission service
Special Protection Schemes	Defines as an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.	• The identified Special Protection System (SPS) metric provides an indication as the extent to which SPSs are relied upon in RTO regions, either on a permanent or interim basis until a transmission

Metric	Criteria	Purpose
		planning solution can be implemented. • This metric also indicates the effectiveness of SPS operations by indicating the number of SPS activations in which the SPS operated as expected as well as number of SPS activations that were not intended.

(b) Please refer to Table 2 and Table 3 below for the requested information

Table 2. Coordinated Wholesale Power Markets[2]

Metric	Criteria	Purpose
Market Competitiveness	**Price Cost Markup** • Represent the load weighted average markup component of dispatched generation divided by the load weighted average price of dispatched generation. The markup component of price is based on a comparison between the price-based offer and the cost-based offer	To assess the competitiveness of the ISO's/RTO's markets.

[2] All information describing criteria and purpose has been extracted from the 2010 ISO/RTO Metrics Report, available at: http://www.isorto.org/Documents/Report/2010IRCMetricsReport_2005-2009.pdf

Metric	Criteria	Purpose
	of each actual marginal unit on the system. • Relatively low price cost markup percentages are strong evidence of competitive behavior and competitive market performance **Generator Net Revenues** • Net revenue quantifies the contribution to total fixed costs received by generators from ISO/RTO energy, capacity and ancillary service markets and from the provision of black start and reactive services. **Mitigation** • Reflects the percentage of generator unit hours prices were capped in the respective ISO's/RTO's real-time energy market due to mitigation.	
Market Pricing	**Average Annual Load-weighted Wholesale Energy Prices** • Shows the average annual load-weighted wholesale electricity energy spot prices in ISOs/RTOs with no adjustment for fuel cost changes or for different fuel mixes in different regions. **Fuel-adjusted Wholesale Prices** • Shows the average annual load-weighted wholesale electricity energy spot prices, adjusted for changes in fuel costs. **Breakdown of the Components of Wholesale Total Power Costs** • Breaks down the components of the wholesale power costs relative to	

Metric	Criteria	Purpose
	the various tariffs administered by each ISO/RTO.	
Unconstrained Energy Portion of System Marginal Cost	The average, non-weighted, unconstrained energy portion of the system marginal cost measures the marginal energy price in dollars per megawatt hour exclusive transmission constraints and transmission losses.	
Energy Market Price Convergence	Reflect the absolute value and percentage of the average annual difference between real-time energy market prices and the day-ahead energy market prices.	Good convergence between the day-ahead and real-time prices is a sign of a well-functioning day-ahead market.
Congestion Management	• The first congestion measure is calculated as the annual congestion costs of each ISO/RTO region divided by the megawatt hours of load served in that ISO/RTO. • The second measure is calculated as the percentage of congestion revenues paid divided by the actual congestion charges.	To assess the performance of an ISO/RTO with respect to the cost of congestion.
Resources	**Generator Availability** • Shows the actual average annual generator availability for each ISO/RTO calculated as one minus the Equivalent Demand Forced Outage Rate. **Demand Response Availability** • Shows what percentage of committed Demand Response resources were either available when called upon by the ISO/RTO or were available via testing performed by the ISO/RTO.	• Competitive wholesale power markets have provided incentives for generation owners to take actions to achieve higher power plant availability and lower forced outage rates, particularly during peak demand periods. This has reduced the cost of producing electricity. • A tool available to ISOs/RTOs to balance customer demand

Metric	Criteria	Purpose
		and available generation is to call upon committed Demand Response resources to reduce customer demand in times of high usage.
Fuel Diversity	Fuel Diversity is the mix of fuel types installed and available (capacity) or used (generation) to produce electricity in each ISO/RTO.	
Renewable Resources	Measures the installed renewable capacity (MWs) as a percentage of total capacity (MWs) and renewable energy production (MWhs) as a percentage of total energy (MWhs).	To stimulate investment in renewable generation.

Table 3. Organizational Effectiveness[3]

Metric	Criteria	Purpose
ISO/RTO Administrative Costs	• Compare annual actual costs incurred by the ISO/RTO to the approved administrative fees and budgeted costs (net revenue requirement). • Generally speaking, a percentage of actual expenses to budgeted expenses as close to 100% as possible is favorable.	• On an annual basis a small variance from 100% means that the ISO/RTO is forecasting the financial needs of the organization and effectively managing the business to the budget. • Taking a longer-term view will provide a trend analysis that indicates the relative

[3] All information describing criteria and purpose has been extracted from the 2010 ISO/RTO Metrics Report, available at: http://www.isorto.org/Documents/Report/2010IRCMetricsReport_2005-2009.pdf

		stability of the organizations' cost performance.
Customer Satisfaction	Each ISO/RTO asks its own set of unique questions of its customers.	To better understand the customer satisfaction landscape and to develop specific actions in response to customer feedback.
Billing Controls	• There are two types of Statement of Auditing Standard 70 (SAS 70) audits: Type 1 audits which assess the adequacy of the control design and Type 2 audits which both review the adequacy of the control design and whether the controls are being followed. The table in this section that summarizes the type of SAS 70 audit undertaken by each ISO/RTO and what type of opinion was issued by the independent auditor for each year's SAS 70 audit. • Summarizes the type of SAS 70 audit undertaken by each ISO/RTO and what type of opinion was issued by the independent auditor for each year's SAS 70 audit.	To enhance customer confidence in the ISO/RTO controls surrounding these billing processes and to assist public companies that are ISO/RTO members.

SECTION 2. ADDITIONAL INFORMATION

Bulk Power System Reliability

Different reliability standards apply to different ISOs and RTOs. All ISOs and RTOs are responsible for compliance with North American Electricity Council (NERC) mandatory standards and any mandatory standards for the Regional Entities (RE) that apply in the region where the ISO/RTO is located and are subsequently adopted by NERC. The mandatory reliability standards only apply to ISO/RTOs based on the NERC functional model categories for which each ISO/RTO has registered.

Specifically, each region may have reliability standards that apply only within that region, given the particular infrastructure, resource mix, topographical and other differences that exist within the region. The main differences between the ISO/RTO applicable standards are the Regional Entity standards. Each region develops standards applicable for their infrastructure, environment and any other regional differences. Each ISO/RTO may also be registered for different functions, causing them to comply with different reliability standards.

Violations of such standards may be identified by an ISO/RTO and self-reported or may be identified by a NERC and/or Regional Entity audit of the ISO's/RTO's standards compliance. Such violations can then be classified as low, medium or high severity. This metric is a quantification of all NERC and RRO Reliability Standards violations that have been identified during an audit or as a result of an ISO/RTO self-report and have been published as part of that process.

Coordinated Wholesale Power Markets

Because average real-time energy prices correlate to short-term forward bilateral prices, ISO/RTO markets foster forward contracting that can stabilize prices. Organized markets offer diverse power products and services, as well as an array of markets that can be used to hedge against price risks. Increased and more accurate price transparency means better contract pricing.

By using advanced technologies and market-driven incentives, the commitment and dispatch of the generators within regional markets is more efficient than those absent regional markets. The centralized market commitment and dispatch allows the most cost-effective unit in the region to be fully utilized before the next most cost-effective unit, etc. In addition, the market incentives motivate generation owners to keep their plants available particularly during peak periods.

Security-constrained economic dispatch of generators performed by ISOs/RTOs also allows the transmission system to be more fully utilized and congestion to be managed on an economic basis as opposed to the strict "rights" based Transmission Loading Relief methodology. ISOs/RTOs are well-equipped to analyze and actively manage the reliability and economic considerations of congestion on the power grid and identify more efficient investment opportunities for upgrades and new facilities.

Organizational Effectiveness

The members of ISOs/RTOs are looking for services to be rendered by the ISO/RTO in a cost-effective manner while addressing members' needs and billing transactions accurately.

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BOMA INTERROGATORY 28

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p52***

Has the IESO ever incurred any notifications and/or penalties from NERC or the NPCC over the last five years for violation of Violation Risk Factors ("VRF") assigned High, Medium, or Lower? If so, what were the incidents, and what remedial action was taken?

RESPONSE

The IESO is not subject to penalties from NERC or NPCC. Under Ontario's Reliability Compliance framework, sanctions are levied by the IESO's Market Assessment and Compliance Division. Over the last five years, the IESO was sanctioned for non-compliance related to two events. The enforcement sanctions that have been applied by MACD are as follows[1]:

1. Independent Electricity System Operator (IESO): On December 19, 2014, the IESO was sanctioned for failing to comply with four North American Electric Reliability Corporation (NERC) reliability standards on two separate dates. The four standards – TOP-002-2b R6, TOP-002-2b R10, IRO-005- 3a R1.3 and TOP-002-2b R19 – relate to the IESO's functions as Transmission Operator, Balancing Authority and Reliability Coordinator.

   The IESO self-reported that on March 26, 2012 they failed to account for all potential contingencies – or unplanned system events – involving power system elements in the Bruce area when they developed and implemented an operating plan. The error occurred as the IESO prepared for a planned transmission outage. As a result of this oversight, the IESO failed to recognize and prepare for a post- contingency system configuration that might have compromised reliability of the bulk power system, if the contingency had occurred. Although these breaches did not have an impact on reliability in real time, they exposed the power system to increased risk.

   The IESO also self-reported that on April 27, 2012 they failed to maintain accurate computer models utilized for analyzing and planning system operations. Specifically, a contingency that should have been modelled was not included in the IESO's Security Analysis program as required by the standard. This omission resulted in the IESO not preparing for the generation loss associated with the most severe single contingency that

[1] http://www.ieso.ca/en/sector-participants/market-oversight/rule-compliance/compliance-enforcement/sanctions

could affect the system. This failure had no actual impact on reliability as contingency conditions did not materialize in real time.

MACD's assessed sanction for these two events was reduced to a $16,000 penalty after consideration of all relevant penalty factors. The main mitigating factor was the IESO's proactive self-report in these matters. In addition, MACD considered the significant costs incurred by the IESO in respect of the voluntary implementation of mitigation plans and other additional compliance measures following these events. Spending on these measures totalled more than $800,000. The measures are intended to reduce the likelihood of similar events and strengthen the controls used by the IESO to manage Bruce-area outages. In keeping with MACD's primary objective of fostering reliability via compliance with the market rules, these investments serve as the most effective vehicle.

In addition to the events noted above, the IESO self-reported 9 additional non-compliance events in the last five years. All were classified as low or medium violation risk factor and were addressed through mitigation plans approved by NPCC. In general, mitigation plans include the strengthening of internal controls such as additional staff training, procedural changes, or enhancements to operational displays and alarming.

BOMA INTERROGATORY 29

Issue 5.1

INTERROGATORY

Ref: ***Ibid, p56***

Please provide copies of both surveys and the description of the "melding process" to achieve the reported satisfaction level.

RESPONSE

Please refer to the response to BOMA Interrogatory 6 at Exhibit I, Tab 5.1, Schedule 2.06.

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ED INTERROGATORY 1

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

1. Please provide the annual transmission losses (TWh) of the IESO-controlled Ontario electricity transmission system for each of the last ten years.

RESPONSE

1. The IESO believes that the requested information is not relevant to the current proceeding. As stated in the Board-approved settlement agreement in the IESO's 2016 revenue requirement submission (EB-2015-0275), the scorecard is intended to "be a tool for the Board and intervenors to use in evaluating the IESO's proposed expenditure and revenue requirement". As described in Exhibit C-1-1, the IESO is of the view that transmission losses are not indicators of the cost effectiveness of IESO activities but rather of the overall attributes and characteristics of the electricity system in Ontario.

   To provide further context, transmission losses are one of many complex and sometimes competing priorities that the IESO must constantly balance in fulfilling its objects across its diverse functions. "Optimizing" transmission line losses over other priorities would entail economic, social and environmental policy trade-offs that could come at an ultimate cost to ratepayers. For example, a 500 kV versus a 230 kV transmission line would mean lower losses but would be a significantly greater capital expenditure and limit the amount and type of resources that could be connected to it due to reliability concerns. Similarly, the overall cost of one generator's supply may be lower than another's even if dispatching the supply would lead to higher transmission losses. All of these factors and system attributes must be considered in the overall balancing of the electricity system and are influenced by, amongst other things, reliability requirements, policy initiatives, and stakeholder priorities.

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ED INTERROGATORY 2

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

2. Please state the annual transmission losses of the IESO-controlled Ontario electricity transmission system as a percentage of its annual throughput volumes for each of the last ten years.

RESPONSE

2. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01.

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ED INTERROGATORY 3

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

3. Please state the financial cost to Ontario electricity consumers of Ontario's annual transmission losses for each of the last ten years. Please show your assumptions and calculations. If the IESO calculates the financial cost to consumers based only on the HOEP, please also provide a calculation of the financial cost that includes all costs included in the Global Adjustment Charge.

RESPONSE

3. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01.

As described in Exhibit C-1-1, the IESO is of the view that transmission losses are not indicators of the cost effectiveness of IESO activities. As a result, the costs associated with these transmission losses are also not indicators of the cost effectiveness of IESO activities.

For further clarification, costs associated with system-wide transmission line losses are a component of the Net Energy Market Settlement Uplift (charge code 150). The charge covers differences between the amount paid to suppliers for the commodity and the amount paid by buyers in a given hour. The Net Energy Market Settlement Uplift is the only settlement mechanism in Ontario's wholesale electricity market through which market participants are charged for costs attributed to system-wide transmission losses and is recovered through the wholesale market service charge. In the Board's August 4 Decision on the issues list for this proceeding, the Board determined that it will not review the wholesale market service charge in this proceeding[1].

The IESO believes that review of the settlement of costs attributed to transmission losses is therefore out of scope of the current proceeding. In an effort to be of assistance to parties, the IESO provides the following additional context.

The settlement methodology for transmission losses was recommended by the government-appointed Market Design Committee and accepted by the IESO's Technical Panel prior to the opening of Ontario's wholesale competitive electricity market in May

[1] Page 7 of the OEB's August 4, 2017 Decision (EB-2017-0150) on Issues List

2002. A change to the methodology should be subject to comprehensive review and input from stakeholders through the appropriate forums, including the IESO Technical Panel.

The global adjustment (GA) framework and equation, which does not include a factor for transmission line losses, are set out in government regulation. The GA is intended to cover the cost for providing both adequate future generating capacity and conservation programs for Ontario. As such, the associated GA costs cannot be directly attributed to volumes of electricity flowing across Ontario's transmission lines and the associated losses.

ED INTERROGATORY 4

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

4. Please provide the annual peak hour transmission losses of the IESO-controlled Ontario electricity transmission system for each of the last ten years.

RESPONSE

4. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01

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ED INTERROGATORY 5

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

5. Please state the annual peak hour transmission losses of the IESO-controlled Ontario electricity transmission system as a percentage of its annual peak hour demands for each of the last ten years.

RESPONSE

5. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01.

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ED INTERROGATORY 6

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

6. Please state the financial cost to Ontario's electricity consumers of Ontario's annual peak hour transmission losses for each of the last ten years. Please show your assumptions and calculations. If the IESO calculates the financial cost to consumers based only on the HOEP, please also provide a calculation of the financial cost that includes all costs included in the Global Adjustment Charge.

RESPONSE

6. Please refer to the response to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03.

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ED INTERROGATORY 7

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

7. Please describe in detail how transmission losses are measured, how the cost of transmission losses are recovered, which entities/customers bear those costs, and in what approximate proportion the various entities/customers bear those costs.

RESPONSE

7. Please refer to the response to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03.

   In an effort to be of assistance to parties, the loss component of the Net Energy Market Settlement Uplift is essentially the difference between system-wide AQEI (allocated quantity of energy injected at defined metering points), AQEW (allocated quantity of energy withdrawn at defined metering points), SQEW (scheduled quantity of exports withdrawn at defined intertie metering points) and SQEI (scheduled quantities of energy injected at defined intertie metering points) quantities at the 5-minute Energy Market Reference Price for each metering interval in the settlement hour. The hourly Ontario energy price (HOEP) is the hourly average of the 5-minute market price.

   Costs are recovered from each consumer based on the net amount of electricity it consumed during the applicable settlement period.

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ED INTERROGATORY 8

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

8. Please describe in detail:
   a. How the Net Energy Market Settlement Uplift is calculated;
   b. The purpose of the Net Energy Market Settlement Uplift; and
   c. The ways in which that purpose differs from the purpose of calculating the total cost of losses to electricity consumers.

RESPONSE

a. Please refer to the responses to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03, and to ED Interrogatory 7 at Exhibit I, Tab 5.1, Schedule 4.07.
b. Please refer to the response to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03.
c. Please refer to the response to ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03

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ED INTERROGATORY 9

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

9. Please list and describe all of the actions and processes by which the IESO optimizes or could optimize the level of transmission losses (e.g. generation siting, generation dispatch, voltage control, identification of incremental line or equipment investments, expansion of demand response, etc.). Please provide a full and comprehensive response.

RESPONSE

9. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01.

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ED INTERROGATORY 10

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

10. Please list and describe all of the actions and processes for optimizing transmission losses that are the responsibility of entities other than the IESO. For each action and process, please describe any role that the IESO plays with respect to those actions and processes or, where appropriate, please indicate that the IESO plays no role at all whatsoever.

RESPONSE

10. Please refer to the responses to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01, and ED Interrogatory 9 at Exhibit I, Tab 5.1, Schedule 4.09. The IESO is of the view that the actions and processes that are the responsibility of other entities are also not relevant to the current proceeding.

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ED INTERROGATORY 11

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

11. Please provide all IESO reports, policies, procedures, standards, or other similar such documents that describe what the IESO does to optimize transmission losses.

RESPONSE

11. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01. In an effort to be of assistance to parties, the IESO also provides the following context.

    In regards to our planning activities, the IESO follows good utility practice in considering transmission losses as one of many complex and sometimes competing priorities that the IESO must balance. It conducts assessments of the economic impact of power system losses when such losses could reasonably be consequential to the selection of a least cost plan. Example of such analysis can be found in the IESO’s Feasibility Study for the East-West Tie and in the Appendix to the Pickering-Ajax-Whitby Integrated Regional Resource Plan.

    When operating the power system, the IESO is required to consider losses when scheduling resources as stipulated in the IESO’s Market Rules and associated manuals.

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ED INTERROGATORY 12

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

12. The European Regulators' Group for Electricity and Gas states that "it is important to ensure that network operators face adequate incentives so that they make an appropriate effort on evaluating the costs and benefits of reducing losses and, hence, optimise the level of losses in the most efficient way."[1] Does the IESO agree with this statement? Please explain why or why not.

RESPONSE

12. Please refer to the response to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01 for an explanation as to why the "optimization" of losses does not necessarily lead to cost effective outcomes relative to other factors. With this in mind, the IESO believes that the requested information is not relevant to the current proceeding.

[1] European Regulators' Group for Electricity and Gas, *Treatment of Losses by Network Operators ERGEG Position Paper for public consultation*, Ref: E08-ENM-04-03, July 15, 2008 (http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Treatment%20of%20Losses/CD/E08-ENM-04-03_Treatment-of-Losses_PC_2008-07-15.pdf)

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ED INTERROGATORY 13

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

13. If the Board were to direct the IESO to measure and monitor the effectiveness of its efforts to optimize the level of transmission losses, please compare, rank, and discuss the appropriateness of the following metrics:
    a. Annual transmission losses (TWh);
    b. Annual transmission losses (TWh) as a percent of total annual transmission throughput volumes (TWh);
    c. Total annual cost of transmission losses to consumers; and
    d. Total annual cost of transmission losses to consumers per TWh of total annual transmission throughput volumes.

RESPONSE

13. Please refer to the responses to ED Interrogatory 1 at Exhibit I, Tab 5.1, Schedule 4.01, and ED Interrogatory 3 at Exhibit I, Tab 5.1, Schedule 4.03.

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ED INTERROGATORY 14

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Ex. C-1-1, p. 4 and Ex.C-1-1, Attachment 1, p. 36

14. If the IESO wished to measure and monitor the effectiveness of its efforts to optimize the level of transmission losses or the Board were to direct it to do so, what metric(s) would it use? Please explain.

RESPONSE

14. Please refer to the responses to ED Interrogatory 9 at Exhibit I, Tab 5.1, Schedule 4.09, and ED Interrogatory 13 at Exhibit I, Tab 5.1, Schedule 4.13.

    The IESO is not in a position to comment on what metric the OEB would determine as most appropriate to measure and monitor the effectiveness of efforts to optimize the level of transmission losses, particularly given the IESO's limited control of electricity system characteristics that influence losses.

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ED INTERROGATORY 15

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

15. Please provide the TRC Test net benefits of the IESO’s CDM programs for each of the past ten years.

RESPONSE

15. The TRC test net benefit of the IESO’s CDM programs for each of the past ten years is shown in the table below. Verified TRC test net benefit values for 2016 and 2017 have not yet been finalized.

#	Year	Public Report TRC Figures			
		Benefit ($)	Costs ($)	Net Benefit ($)	Net Benefit Ratio
1	2015	924	727	204M	1.3
2	2014	873M	624M	249M	1.4
3	2013	563 M	461 M	102 M	1.2
4	2012	466 M	351 M	114 M	1.3
5	2011	623 M	521 M	102 M	1.2
6	2010	541 M	524 M	18 M	1.0
7	2009	412 M	356 M	56 M	1.2
8	2008	293 M	187 M	106 M	1.6

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ED INTERROGATORY 16

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

16. Would the IESO object to the inclusion of the TRC Test net benefits of its CDM programs as one of its Regulatory Scorecard's metrics? If yes, please fully explain and justify the IESO's objections.

RESPONSE

While the TRC test net benefit data for the CDM programs is available, the IESO believes such a metric would provide limited value to the regulatory scorecard and does not recommend that it be included. The TRC includes program costs, participant costs and the cost of other externalities, such as equipment, which can cause the TRC to change, even though the cost may be out of the IESO's control. As such, the IESO does not believe that the TRC provides significant insight in evaluating the IESO's proposed expenditure and revenue requirement.

As described in Exhibit C-1-1 and its Attachment 1 (the "Elenchus" report), stakeholders were generally supportive of the proposed metrics for conservation in the IESO regulatory scorecard, which include annual reporting of portfolio costs ($/kWh) and achievement of 2020 energy savings target milestones (TWh). Together, these metrics will show whether adequate progress is being made toward the conservation targets that have been established by the Province.

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ED INTERROGATORY 17

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

17. Please provide the IESO’s rationale for proposing the conservation metric of “annual reporting of portfolio cost ($/kWh).”

RESPONSE

On page 27 of Exhibit C-1-1, Attachment 1, the “Elenchus” Report states that as long as CDM remains a priority for the IESO, a measure of cost-effective CDM delivery will be appropriate for the regulatory scorecard.

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ED INTERROGATORY 18

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

18. Please:
    a. Explain in detail the basis for the proposed target of within 0.04$/kWh for the cost of conservation per kWh;
    b. Indicate whether the government has approved that target, and if yes, include documentation indicating as such; and
    c. Provide any studies, reports, or presentation prepared by the IESO in relation to that proposed target.

RESPONSE

a. Within $0.04 / kWh is not a target, rather it is the performance level that has been consistently achieved by the conservation portfolio over a number of years. Within $0.04 / kWh is he levelized cost of delivery, which reflects the acquisition costs of conservation investments divided by lifetime savings of the conservation measures. This calculation is described on page 15 of the IESO's CDM Cost Effectiveness Guide which is provided as Attachment 1.

b. Government approval is not required. Please refer to the response to part (a) above.

c. Please refer to the response to part (a) above.

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Conservation & Demand Management Energy Efficiency Cost Effectiveness Guide

Independent Electricity System Operator

March 2015

Table of Contents

LIST OF FIGURES

1 Introduction

This Cost Effectiveness Guide ("Guide") describes standard industry metrics to assess the cost effectiveness of conservation and demand management (CDM) resources. The Guide may be updated from time to time. Cost effectiveness assesses whether the benefits of an investment exceed the costs.

Cost effectiveness metrics include:

- Tests, which are benefit-cost analyses; and,
- Levelized delivery cost metrics, which express the costs per unit of peak demand or energy savings.

Cost effectiveness metrics can be used to assess CDM from both a screening perspective during planning stages and from an evaluation perspective as part of the evaluation, measurement and verification (EM&V) process.

Standard industry cost effectiveness metrics contained in this Guide can be applied differently depending on regulatory and policy frameworks. The National Action plan for Energy Efficiency's November 2008 report *Understanding Cost-Effectiveness of Energy Efficiency Programs*, for example, provides a jurisdictional review of cost effectiveness practices and issues in the United States, which readers of this Guide may find useful for additional background information[1].

This Guide is primarily intended to provide detailed guidance on the assessment of Energy Efficiency (EE) resources and is intended to complement, not replace, the policies, concepts, and procedures relating to CDM in Ontario found in the IESO's *EM&V Protocols & Requirements.*[2] In addition, Demand Response (DR) resources should be assessed using the IESO's *Protocols for Estimating Load Impacts Associated with Demand Response Resources in*

1 National Action Plan Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. November 2008. Available at: http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

2 Available at: http://powerauthority.on.ca/sites/default/files/20110331%20-%20EMV%20Protocols%20and%20Requirements.pdf

Ontario[3]. Section 6.2 of this Guide contains guidance on how to aggregate EE and DR resources when assessing cost effectiveness.

3 Protocols for Estimating Load Impacts Associated with Demand Response Resources in Ontario. December 2009. Available at: http://www.powerauthority.on.ca/sites/default/files/OPA%20DR%20Load%20Impact%20Protocols_2009.pdf

2 Structure of the Guide

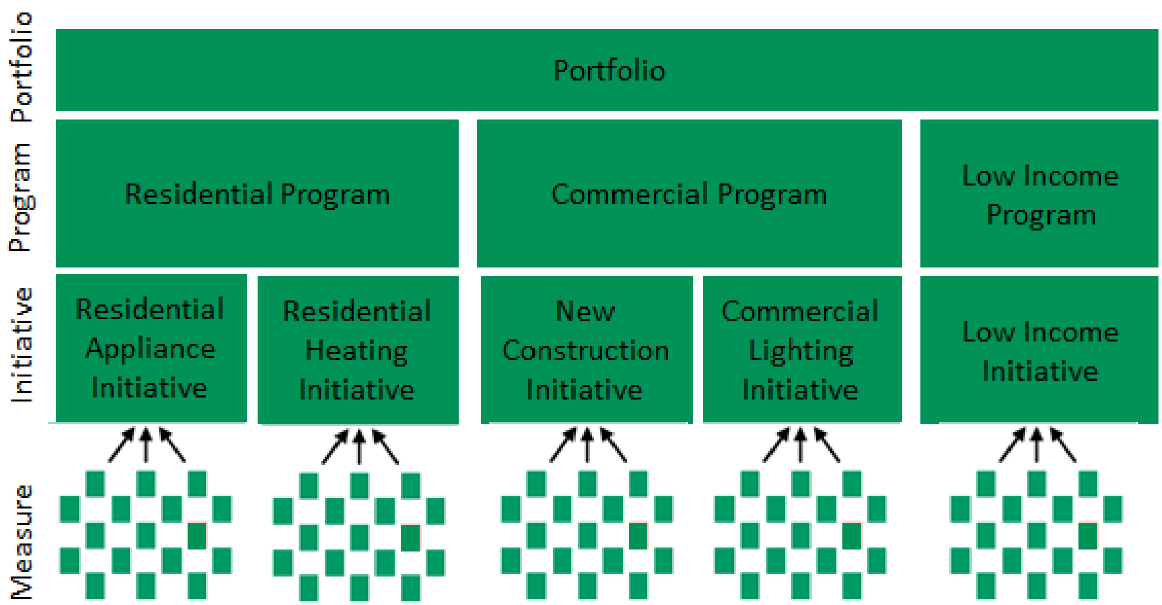
This Guide is structured in the following five key sections:

- **Use of Cost Effectiveness Metrics** describes at a high-level how various cost effectiveness metrics are used, their inputs, strengths, and weaknesses.
- **Concepts & Components of Cost Effectiveness Metrics** is broken down into two sub-sections: concepts and components. The concepts sub-section provides foundational information required to compute the cost effectiveness components. The components section provides detailed instructions to calculate each component used in all cost effectiveness metrics.
- **Calculation of Cost Effectiveness Metrics** specifies the components used in each metric and how to calculate each metric.
- **Cost Effectiveness Guidelines** discusses important considerations when deriving the inputs and outputs to a cost effectiveness analysis.
- **Special Cases/Examples** provides guidance on the categorization of costs that may be ambiguous or require interpretation.

3 Use of Cost Effectiveness Metrics

CDM can be assessed at various levels of detail: measure, program, or portfolio. The measure is the most granular level of CDM and represents the conservation technology, product, or action implemented by a participant. A program is a collection of measures or activities targeted towards, for example, a particular end-use (e.g., lighting) or customer type (e.g., small commercial). A portfolio is a collection of programs. Figure 1 outlines an illustrative example of the levels of CDM implementation.

Figure 1: Levels of CDM Implementation



The use of multiple tests when screening CDM measures programs or portfolios provides a well-rounded assessment of cost effectiveness. Each metric is used to assess cost effectiveness from a different perspective and can be used for different purposes. Different jurisdictions will emphasize different tests depending on the policy environment and objectives of that particular jurisdiction.

Figure 2 outlines each metric, the key question it answers and a brief summary of the approach. Cost effectiveness tests are comparisons of benefits and costs expressed as both the dollar value of the net benefit (or cost) and as a ratio of benefits to costs. The remainder of this section is split into sub-sections, each describing the metrics listed in

Figure 2.

Figure 2: Overview of Cost Effectiveness Metrics

Metric	Key Question Answered	Summary Approach
Total Resource Cost (TRC) test	How will the total costs of energy and demand in the utility service territory be affected?	Compares the costs incurred to design and deliver programs and customers' costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, natural gas, etc.)
Societal Cost (SC) Test	Is the utility, state or nation better off as a whole?	Identical to TRC approach, but also includes the cost of "externalities" (e.g., carbon emissions, health costs, etc.)
Program Administrator Cost (PAC)Test	How will utility costs be affected?	Compares the costs incurred to design and deliver programs by the program administrator with avoided electricity supply-side resource costs[4]
Ratepayer Impact Measure (RIM) Test	How will utility rates be affected?	Compares administrator costs and utility bill reductions with avoided electricity and other supply-side resource costs
Participant Cost (PC) Test	Will the participant benefit over the measure life?	Compares costs and benefits of the customer installing the measure
Levelized Delivery Cost (LC)	What is the per-unit cost to the utility?	Normalizes the costs incurred to design and deliver programs per unit saved (i.e., peak demand or energy savings)

[4] The PAC test only includes electricity system related costs because of the Ontario context. If a utility is responsible for other resources (e.g., natural gas), these costs would be included as well.

3.1 Total Resource Cost (TRC) Test

Description & Perspective: The TRC test compares the costs incurred to design and deliver programs and customers' costs with the avoided electricity and other supply-side resource costs (generation, transmission, natural gas, etc.).

Inputs:

Costs:

- The expenses incurred by a program administrator to design and deliver CDM.
- The incremental expenses incurred by participants to implement the conservation action.

Incentives provided to participants from the program administrator to entice participation in CDM programs are *not* included in the TRC test as these are simply a transfer from the program administrator to participating customers.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:
  - Generation costs;
  - Transmission and distribution (T&D) costs;
  - Fuel costs; and,
  - Operations and maintenance (O&M) costs.
- Other avoided supply-side resource costs (e.g., natural gas).

Strengths: The strength of a TRC test is that it provides a holistic viewpoint, by considering costs incurred by, and benefits that accrue to, both the utility and the participant.

Weaknesses: The TRC test does not consider the effects of revenue reduction and other non-energy benefits.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

3.2 Societal Cost (SC) Test

Description & Perspective: The SC test is identical to the TRC approach, but also includes the cost of "externalities," for example, increased comfort, environmental improvements (i.e., reductions in carbon emissions, better air/water quality); reduction in health costs/improved health, and public/national security. The SC can also be referred to as an extended TRC test.

Inputs:

Costs:

- Same as the TRC test.

Benefits:

- Same as the TRC test.
- Non-resource or non-energy benefits such as avoided carbon, reduced water consumption or improved water quality, and avoided health costs.
- Some jurisdictions apply a lower discount rate or adder to the benefits to account for the greater uncertainty associated with non-resource and non-energy CDM benefits.

Strengths: The primary strength of the SC test is that, in addition to capturing the direct benefits and costs to the program administrator and participants, it captures both direct and indirect benefits to society as a whole by including the externalities mentioned above.

Weaknesses: However, the scope of indirect costs and benefits may be too broad for some stakeholders and non-energy benefits can be difficult to quantify.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

3.3 Program Administrator Cost (PAC) Test

Description & Perspective: The PAC test compares the costs incurred to design and deliver programs by the program administrator with avoided electricity supply-side resource costs[5] from the perspective of the program administrator.

Inputs:

Costs:

- Total expenses incurred by a program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:
  - Generation costs;
  - Transmission and distribution (T&D) costs;
  - Fuel costs; and,
  - Operations and maintenance (O&M) costs.

Strengths: The PAC test does not include an estimate of lost revenue, and therefore is not complicated by uncertainty in rates in the short or long-term.

Weaknesses: It does not capture the participant costs or potential rate impacts of CDM.

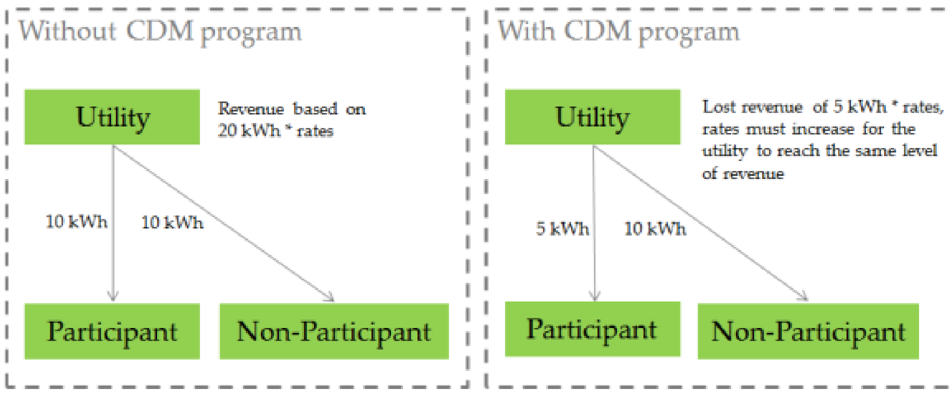
For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

[5] The PAC test only includes electricity system related costs because of the Ontario context. If a utility is responsible for other resources (e.g., natural gas), these costs would be included as well.

3.4 Ratepayer Impact Measure (RIM) Test

Description & Perspective: The RIM test compares program administrator costs and utility lost revenue with avoided electricity and other supply-side resource costs for all ratepayers due to CDM. The RIM test captures the transfer of costs from participant to non-participants. This transfer of costs occurs due to the utility's need to recover lost revenue (due to conservation) through rates (paid by participants and non-participants alike). Figure 3 provides a simple illustrative example to demonstrate this concept.

Figure 3: Concept of Lost Revenue to Utility



Inputs:

Costs:

- Utility's lost revenue as a result of customers using less electricity.
- Expenses incurred by a program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- The electricity system related costs that are no longer required as a result of the savings achieved by CDM, including:
  - Generation costs;
  - Transmission and distribution (T&D) costs;
  - Fuel costs; and,
  - Operations and maintenance (O&M) costs.

- Other avoided supply-side resource costs (e.g., natural gas).

Strengths: The RIM test captures the cost transfer (as a result of lost revenue) resulting from CDM.

Weaknesses: The RIM test is sensitive to projections of long-term rates and marginal costs, which may be hard to predict. As a result, additional analysis beyond a RIM test may be needed to fully assess impacts to rates and account for the effect of reduced energy demand on longer-term rates and customer bills.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

3.5 Participant Cost (PC) Test

Description & Perspective: The PC test compares costs and benefits of CDM from the perspective of the participating customers. The PC test is typically used for informational purposes and to assist with program design and planning. It may be used as an input to support the development of incentive levels.

Inputs:

Costs:

- Additional expenses incurred by participants to implement the conservation action (i.e., the incremental costs of participating).

Benefits:

- Bill savings due to reduced consumption of electricity and other resources (e.g., natural gas, water).
- The cost of providing incentives provided to participants to entice participation in the program.
- Any reductions in O&M costs as a result of the CDM.

Strengths: The PC test is useful for program design, particularly in developing incentive levels and participation goals. The PC test is also helpful to assess the desirability of a program to potential participants.

Weaknesses: The PC test does not fully capture the customer decision-making process since it does not account for customers' qualitative judgments.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

3.6 Levelized Delivery Cost (LC)

Description & Perspective: The LC normalizes the costs incurred by the program administrator per unit of energy or demand reduced. The levelized delivery cost is also referred to as the "Levelized Unit Energy Cost" (LUEC) when assessing costs per unit of energy savings achieved.

Inputs:

Costs:

- Total expenses incurred by the program administrator to design and deliver CDM.
- The cost of providing incentives provided to participants to entice participation in the program.

Benefits:

- Energy savings over the lifetime of the CDM resource.; or,
- Peak demand reduction over the lifetime of the CDM resource.

Strengths: The LC provides a simple basis for comparing the cost of CDM with the cost of other supply-side resources. Like the PAC the LC is not complicated by uncertainty in rates in the short or long-term.

Weaknesses: The LC only reflects a portion of the full costs of CDM - the rate impacts of CDM are not captured. In addition, this metric considers only the direct electricity system benefits of CDM, peak demand or energy savings, and thus does not fully capture the total value of CDM.

For more information regarding the comparison of CDM resources to supply resources, please refer to Section 0.

4 Concepts & Components of Cost Effectiveness Metrics

This section details the concepts and components required to evaluate CDM cost effectiveness using the metrics outlined above. Guidance for the treatment and calculation of benefits and costs are described to ensure consistency in assessing cost effectiveness, thus enhancing the comparability of results. Figure 4 and Figure 5 visually outline how the components, concepts and metrics interact.

Figure 4: Concepts & Components

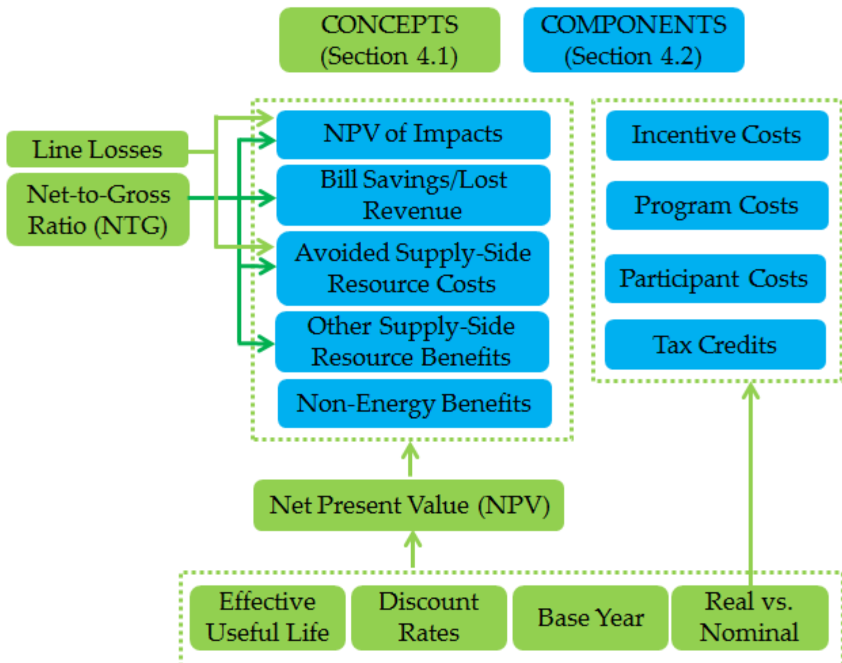


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Figure 5: Components & Metrics

COMPONENTS (Section 4.2)	**Metrics** (Section 5)					
	Total Resource Cost (TRC) Test	**Societal Cost (SC) Test**	**Program Administrator Cost (PAC) Test**	**Ratepayer Impact Measure (RIM) Test**	**Participant Cost (PC) Test**	**Levelized Delivery Cost (LC) Metric**
Avoided Electricity supply-side resource costs	*Benefit*	*Benefit*	*Benefit*	*Benefit*		
Other Supply-Side Resource Benefits	*Benefit*	*Benefit*		*Benefit*		
Bill Savings/Lost Revenue				*Cost*	*Benefit*	
Participant Costs	*Cost*	*Cost*			*Cost*	
Incentive Costs	*Benefit / Cost*	*Benefit / Cost*	*Cost*	*Cost*	*Benefit*	*Cost*
Program Costs	*Cost*	*Cost*	*Cost*	*Cost*		*Cost*
Non-Energy Benefits/Externalities		*Benefit*				
NPV of Impacts						*Benefit*
Tax Credits	*Benefit*	*Benefit / Cost*			*Benefit*	

4.1 Concepts

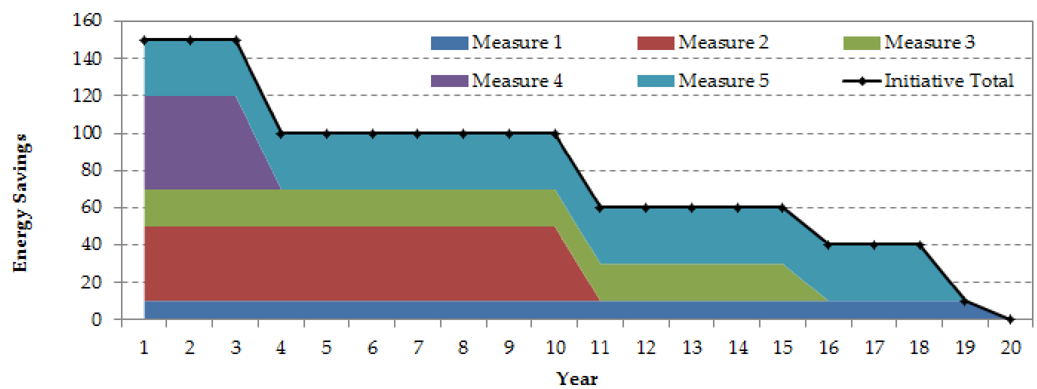
There are several overarching concepts integral to calculations of cost effectiveness. These concepts are used to calculate the components and may also apply to one or more cost effectiveness metrics. Each of the concepts are used to calculate one or more of the cost effectiveness components. The components section will specify which concepts apply.

4.1.1 Effective Useful Life (EUL)

Description: Each measure or conservation action has a length of time over which it will provide peak demand and/or energy savings. For technology-based measures this is typically based on an estimate of the number of years that equipment will operate to a certain standard. EUL is more difficult to define for non-technology or behaviour-based CDM.

Use: When assessing cost effectiveness, the peak demand and/or energy savings that persist over the EUL of a measure determine the benefit (or cost) of that measure. Each measure in a given program may have a different EUL. Measure-level EULs are provided in the IESO's *Measures and Assumptions List*[6] and updated on a regular basis. When assessing cost effectiveness, the benefits must be calculated for each measure using its corresponding EUL and then aggregated to the program and portfolio level. Figure 6 illustrates this concept.

Figure 6: Illustrative Example of Program EUL



Measures in an program may have different EULs.

When calculating the lifetime energy savings of a measure, it is important to understand the status of the existing or baseline measure. In some instances, a technology is replaced at the end of its EUL. This scenario is called "Replace on Burnout." In this case, the savings and costs used to calculate the cost effectiveness components are determined using the difference in the energy use of the efficient technology and the least-cost, code-compliant baseline technology over the EUL of a measure. In other scenarios, participants will replace a technology before the end of its EUL (i.e. while the existing equipment is still functional). This is called "Early retirement" or "Early Replacement" In this scenario, the savings used to calculate the cost effectiveness components are a result of a two-step calculation:

1) The difference in energy use between the efficient and the existing technology for the remaining useful life (RUL) of the existing technology; and

[6] Available at: http://www.powerauthority.on.ca/evaluation-measurement-and-verification

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2) The difference in energy use between the efficient and the code-compliant, baseline technology for the remainder of the EUL of the efficient technology (i.e. EUL-RUL).

When performing the cost effectiveness assessments for early retirement scenarios, it is most accurate to calculate the benefits and costs based on savings relative to the existing and code-compliant technologies.

For example, in year 1, a participant replaces an existing unit with an EUL of 6 years that consumes 10 kWh per year with a more efficient unit that consumes 5 kWh per year. The existing unit is expected to function for an additional three years (i.e. RUL = 3 years). The current code-compliant baseline equipment for this technology consumes 8 kWh per year. From year 1 to year 3 (RUL), the savings is equivalent to difference in consumption between the existing equipment and the new efficient technology (i.e. 10-5=5 kWh). From years 4 to 6 (EUL – RUL), the savings is equivalent to the difference in consumption between the code-compliant, baseline equipment and the new efficient technology (i.e.8-5 = 3 kWh). Lifetime energy savings are the kilowatt hours that are saved over the entire effective useful life of a measure. Lifetime energy savings are the kilowatt hours that are saved over the entire effective useful life of a measure. In the example below, the measure has achieved 24 kWh of lifetime energy savings. Figure 7 illustrates this example.

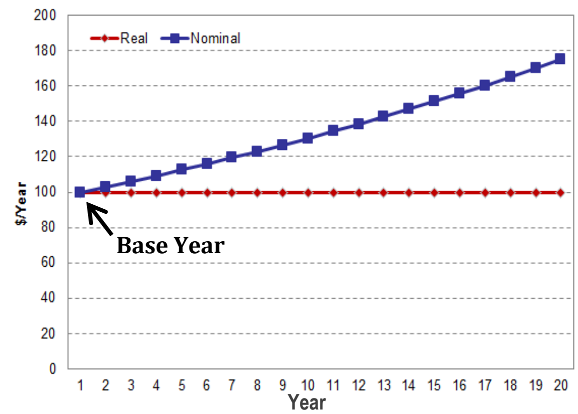
Figure 7: Illustrative Example of Early Retirement

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
	RUL			EUL - RUL		
Existing	10 kWh	10 kWh	10 kWh			
Efficient	5 kWh	5 kWh	5 kWh	5 kWh	5 kWh	5 kWh
Baseline	8 kWh	8 kWh	8 kWh	8 kWh	8 kWh	8 kWh
Savings	5 kWh	5 kWh	5 kWh	3 kWh	3 kWh	3 kWh

Early retirement also impacts the calculation of participant costs. Section 4.2.4 provides additional detail on the determiniation of participant costs in an early retirement scenario.

4.1.2 "Real" (Inflation-Adjusted) vs. Nominal Dollars

Figure 8: Real vs. Nominal Dollars

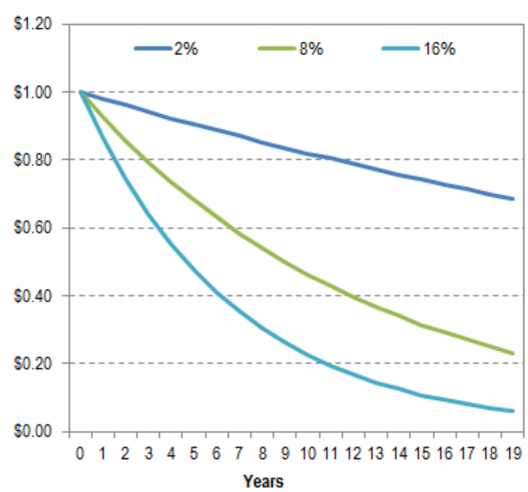


Due to inflation, the value $180 in year 20 would only be $100 when expressed base year dollars

Description: Since the costs and benefits associated with the implementation of CDM are assessed over a span of time – the EUL of a measure – they must be adjusted for forecast inflation. "Nominal" dollars reflect the value of costs and benefits in the year as observed in the year in which they occur (the "sticker price"). "Real" or inflation-adjusted dollars reflect the value of costs and benefits in some given base year's dollars.[7] This allows an "apples to apples" comparison between CDM costs (which are typically much higher in the initial years of a program) and benefits (which tend to be evenly distributed across the lifetime of a measure). Figure 8 illustrates the divergence between "real" and nominal dollars.

Use: When assessing cost effectiveness, it is important to be consistent in the treatment of costs and benefits. Using real dollars to evaluate cost-effectiveness is a leading industry practice that should be followed unless a very strong reason exists not to. The inflation rate used to adjust nominal values is provided in APPENDIX A.

Figure 9: Impact of Varying Discount Rates



The higher the discount rate, the faster the dollar loses value

4.1.3 Discount Rates

Description: The discount rate expresses the time value of money. The time value of money simply means that a dollar available immediately is worth more than a dollar provided a year from now. This difference in value exists because a dollar available immediately may be invested and deliver some returns immediately, whereas a dollar available only

[7] Typically, but not always, the chosen base year is the current year, so for example, benefits realized in 2014, 2015 and 2016 would be expressed in 2013 dollars. Base year will be discussed in more detail in section 4.1.4.

in a year may not be. The time value of money (and thus the discount rate used) is not constant for all individuals, organizations or sectors. For example, the time value of money for government will differ from a private company that must access capital and earn interest through financial markets.

Use: The discount rate can have a large effect on the results of a cost effectiveness analysis. Figure 9 illustrates the impact of various discount rates on the value of $1 over 20 years[8]. The higher the discount rate, the faster the dollar loses value as the delay in acquiring that dollar increases over time. Some jurisdictions will vary the discount rate according to the perspective being evaluated. The discount rates used to evaluate cost effectiveness are provided in APPENDIX A.

When performing a cost effectiveness assessment, the discount rate should be applied to "real" (inflation-adjusted) streams of benefits and costs.

4.1.4 Base Year

Description: The base year selected represents the year that is used as a basis for valuing costs and benefits.

Use: When evaluating single year cost effectiveness, the base year of the analysis typically reflects the year in which CDM is implemented (i.e., the "program year"). However, if desired, a base year that is not the "program year" may be used. When multiple program years of CDM are assessed, a consistent base year should be used to assess benefits and costs to ensure consistency across all program years included in the analysis. Please refer to section 6.2 for more information regarding different screening aggregation.

Note that it is common practice to use the same base year for inflation-adjustment and discounting, it is not required. For example, value of benefits accruing between 2014 and 2020 to a program administrator in 2013 (discounting) could be expressed in 2007 dollars (inflation adjustment).

4.1.5 Net Present Value

Description: The Net Present Value (NPV) incorporates the concepts in sections 4.1.2, 4.1.3, and 4.1.4 to calculate the time value of money.

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[8] Dollars are assumed to be real (inflation-adjusted).

Use: The equation below outlines how to calculate the NPV of costs or benefits, where C_t is the discrete cash flow (i.e., costs or benefits) in real dollars for time period t (i.e., year the costs or benefits occur minus the base year), T is the total number of time periods (i.e., years in the EUL), and d is the discount rate.

$$NPV = \sum_{t=0}^{T} \frac{Ct}{(1+d)^t}$$

4.1.6 Net-to-Gross Ratio (NTGR)

Description: The net-to-gross ratio (NTGR) is an adjustment factor that determines the benefits and costs that are attributable to CDM.

The NTGR may reflect one or more of the following elements[9] (where applicable). Elements of gross savings such as realization rate are not included in this Guide. For full details on the components of both gross and net savings, please refer to the IESO EM&V Protocols & Requirements.[10]

- Free ridership rate (FR): Percentage of participants that would have implemented the CDM measure or conservation action even without the CDM program;
- Spillover (SO): Actions taken by consumers to implement CDM measures without an incentive because they are influenced by the CDM program. Note that both participant and non-participant spillover exists; and,
- Market Effects (ME): Influence of a CDM program on the market behaviour and baselines through increased adoption of energy efficient measures, practices, or services by the broader market.

Use: The NTGR can be applied at the measure-level or at the program-level. In some cases, an element of the NTGR may not be applicable, and thus a value of zero should be used. For instance, market effects do not apply to newly launched programs that have not matured enough to have a lasting impact on the market baseline. In addition, the NTGR is dependent on program design, so it may not be appropriate to use the same NTGR for identical measures in different programs. For example the NTGR for a measure in a coupon program would be different than the NTGR for a measure in a direct install program.

[9] Realization Rate, Interactive Effects, and Snap-back should be considered as part of the gross savings

[10] Available at: http://www.powerauthority.on.ca/benefits/evaluation-measurement-and-verification

The equations below outline how to combine the elements above into a NTGR and how to use the NTGR to determine net savings from gross savings. The individual elements of the NTGR are always expressed as a percentage and thus will fall between 0 and 1. However, the NTGR itself may be greater than 1 in some instances.

$$Net\ to\ Gross\ Ratio = 1 - FR + SO + ME$$

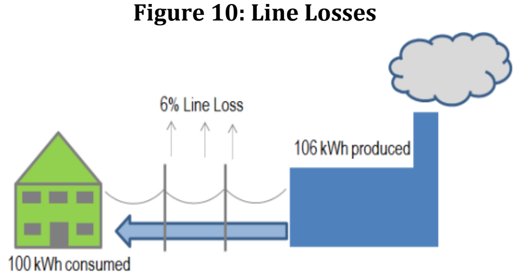
$$Net\ Savings = Gross\ Savings \times Net\ to\ Gross\ Ratio$$

Net savings are not always used when assessing the costs and benefits of CDM. Each component is outlined in section 4.2 and each test is outlined in detail in section 5 and will specify whether it is appropriate to use net or gross savings (i.e., whether or not an NTGR is used).

4.1.7 Line Losses

Description: Line losses occur between energy produced at the generator and energy consumed by the customer or end-user. As a result, energy savings observed by the end-user (the customer) actually understate true savings observed by the generator

Figure 10: Line Losses



Use: Avoided costs, the direct electricity system benefits of CDM, are generally defined at the point of purchase (i.e., at the generator). To accurately capture the full benefits of CDM a line loss factor must be applied to peak demand and energy savings if they are determined at the customer/end-use site.

There are two components used to determine total line losses:

- Average losses on the distribution system (Dx losses); and,
- Average losses on the transmission system (Tx losses).

If a CDM participant is transmission-connected, only the Tx losses are accounted for. If a CDM participant is distribution-connected, both Dx and Tx losses are accounted for. Line losses are provided in APPENDIX A. Line losses are typically provided as a percentage that must be converted into a line loss factor (LLF). The LLF for both Tx and Dx losses is calculated using the equation below.

$$LLF = {}^{1}/_{(1 - (Tx\ Losses\ +\ Dx\ Losses))}$$

Once a LLF is calculated savings at the customer or end-user level can be converted to the generator level using the equation below.

$$Savings_{generator} = Savings_{Customer} \times LLF$$

Savings at the generator are used for valuing avoided electricity supply-side resource costs (i.e., system benefits), and savings at the customer or end-user level are used for lost revenue and bill savings calculations. Each component is outlined in section 4.2 and each test is outlined in detail in section 5 and will specify whether it is appropriate to use savings at the generator level or the end-user/customer level (i.e., whether or not line losses are included).

4.2 Components

Each component outlined in the following section is used to calculate one or more cost effectiveness metrics. Many of the components outlined below may use one or more of the concepts discussed previously.

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (0)
Base Year (4.1.4)
Net Present Value (4.1.5)
Net-to-Gross Ratio (4.1.6)
Line Losses (4.1.7)

4.2.1 Avoided Electricity Supply-side Resource Costs

Description: Avoided electricity supply-side resource costs associated with the implementation of CDM consist of two main components:

- Avoided energy costs; and,
- Avoided capacity costs.

Avoided energy costs account for variable generation costs including the cost of fuel and variable O&M for power plants. Avoided capacity costs account for the reduction in coincident peak demand capacity including avoided generation capacity (i.e., capital and fixed O&M required to build new generation), transmission, and distribution capacity costs.

Use: The avoided supply-side resource costs are calculated using the annual energy savings and annual peak demand savings over the EUL of the measures associated with the implementation of CDM. Savings used in this calculation should account for the NTGR and line losses (i.e., net savings at the generator level) and should be converted to real dollars using a consistent base year.

Use the equation below to determine the total avoided supply-side resource costs.

$$\sum_{i=1}^{I}(\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{i=1}^{I}(\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

Where:

ΔEN_{it} = Net energy savings at the generator level in costing period i in year t (accounting for NTGR and including line losses)

ΔDN_{it} = Net peak demand savings in costing period i in year t, (accounting for NTGR and including line losses)

$MC{:}E_{it}$ = Marginal cost of energy in costing period i in year t

$MC{:}D_{it}$ = Marginal cost of demand in costing period i in year t

K_{it} = 1 when ΔEN_{it} or ΔDN_{it} is positive (a reduction) in costing period i in year t, and zero otherwise (i.e., a switch to count only positive costs)

Calculate the inputs to the equation above using the following steps.

Step 1: Calculate the net annual peak demand and energy savings at the generator level

Net peak demand savings (ΔDN) and energy savings (ΔEN) at the generator level are determined by applying the NTGR and the line loss factor (LLF) to gross energy savings at the end-user. Please refer to sections 4.1.6 and 4.1.7 to review these concepts.

Step 2: Allocate lifetime net annual energy savings at the generator into costing periods

Load profiles provide a percentage breakdown of annual energy savings into eight season and time-of-use buckets, or costing periods, specified in Figure 11. The definition of each costing period can be found in APPENDIX A.

Figure 11: Season and Time-of-Use Periods

Winter			Summer			Shoulder	
On-peak	Off-peak	Mid-Peak	On-peak	Off-peak	Mid-Peak	Off-peak	Mid-Peak

Using the load profiles and the EUL assumptions for each measure in a CDM program or portfolio, allocate each year (t) of net annual energy savings (ΔEN) at the generator level into costing periods (i.e., into eight season and time-of-use buckets). Figure 12 provides a simple illustrative example of how to break down annual savings into costing periods.

Figure 12: Illustrative Example of Savings by Costing Period

Illustrative Example: Net Annual Energy Savings = 10 MWh, EUL = 1

	Winter			Summer			Shoulder	
t = 1	On-peak	Off-peak	Mid-Peak	On-peak	Off-peak	Mid-Peak	Off-peak	Mid-Peak
Load Shape	10%	10%	10%	10%	10%	10%	20%	20%
Calculation of Savings by Bucket	10% X 10 MWh	10% X 10 MWh	10% X 10 MWh	10% X 10 MWh	10% X 10 MWh	10% X 10 MWh	20% X 10 MWh	20% X 10 MWh
Savings by Bucket	1 MWh	1 MWh	1 MWh	1 MWh	1 MWh	1 MWh	2 MWh	2 MWh

Step 3: Multiply the savings by the corresponding marginal cost

To determine the avoided energy cost, multiply the net annual savings (ΔEN_{it}) by the corresponding marginal cost of energy for each costing period for the lifetime of the CDM measure, program, or portfolio $(MC{:}\,E_{it})$. The marginal cost of energy for each costing period and year can be found in APPENDIX A. If the marginal costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

Step 4: Determine the Avoided Capacity Costs

To determine the avoided capacity cost, multiply the net annual peak demand savings (ΔDN_{it}) by the corresponding marginal cost of demand over the EUL of the CDM measure, program, or portfolio $(MC{:}\,D_{it})$. The marginal cost of demand for generation, transmission and distribution by year can be found in APPENDIX A. If the marginal costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

Step 5: Adjust to Reflect NPV

Avoided supply cost assumptions should be discounted to reflect the NPV of lifetime resource savings benefits (i.e., benefits that persist over the EUL of measures) associated with the implementation of CDM. Please refer to section 4.1.5 to review this concept.

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)
Net-to-Gross Ratio (4.1.6)

4.2.2 Other Supply-side Resource Benefits

Description: Other resource benefits resulting from the implementation of CDM may be present in addition to benefits associated with peak demand and energy savings affecting the electricity system. For example, installing insulation could reduce electricity use associated with an air conditioner in the cooling season and also reduce the natural gas use associated with a furnace in the heating season. Avoided supply-side resource costs associated with natural gas, fuel oil, or propane should be included where applicable in the determination of avoided supply-side resource costs for the TRC, RIM, and SC tests only[11].

In some cases, the implementation of CDM may result in the reduction of one supply resource, but an increase in another (i.e., fuel-switching). For example, a gas powered clothes dryer replaces an electric clothes dryer, resulting in a reduction in electricity use, but an increase in natural gas use. Both the reduction in avoided electric supply costs and the increase in natural gas supply costs must be accounted for.

Use: To determine the avoided energy costs for CDM that reduces natural gas, propane, and/or fuel oil consumption, the net annual energy savings for each resource should be multiplied by the corresponding annual avoided cost assumption over the EUL of the CDM measure, program, or portfolio. For example, total natural gas savings (m^3) should be multiplied by the appropriate $/$m^3$ value to determine annual avoided natural gas costs. The avoided cost of other resources by year can be found in APPENDIX A. If the avoided costs are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

4.2.3 Bill Savings/Lost Revenue

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)
Net-to-Gross Ratio (4.1.6)

Description: While reductions in energy and peak demand may lead to bill savings for utility customers, this also results in lost revenue for the utility. Therefore, this can be viewed as a benefit for the customer and as a cost for the utility.

Use: To determine participating customer bill savings associated with CDM, gross annual energy and peak demand savings at the customer or end-user level should be multiplied by annual electricity ratepayer cost assumptions over the EUL of the CDM measure, program, or portfolio. To determine participating utility lost revenue associated with CDM, net annual energy and peak demand savings at the customer or end-user level should be multiplied by annual electricity ratepayer cost assumptions over the EUL of the CDM measure, program, or portfolio. If natural gas, water, propane and fuel oil savings are

[11] The PAC test only includes electricity system related costs because of the Ontario context. If a utility is responsible for other resources (e.g., natural gas), these costs would be included as well.

present, these savings should be included by multiplying the annual savings by the corresponding annual ratepayer assumption. For example, the total natural gas savings in m^3 should be multiplied by the appropriate $\$/m^3$ rate assumption to determine annual natural gas bill savings. Ratepayer assumptions for fuel oil, and propane should be based on their respective avoided costs. Ratepayer cost assumptions for both electricity and other resources can be found in APPENDIX A. If the cost assumptions are not in real dollars using a consistent dollar year, they must be converted to align with all other costs and benefits.

4.2.4 Participant Costs

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)

Description: Participant costs are the incremental capital and O&M costs, incurred by a participating customer to implement CDM. Participant costs are often categorized by the definition of the appropriate baseline which then determines how the costs are derived. The two categories are a) incremental or b) full installed as defined below.

a) **Incremental Cost:** is considered the difference in capital and/or material costs between the baseline and efficient (CDM) equipment. Installation and removal costs are often assumed to be equal for the baseline and efficient case and therefore are not considered a cost to the participant. The incremental cost basis is typically applied to the following scenarios:
   - Replace-on-Burnout (ROB): in the case of an energy efficient appliance being purchased instead of a standard model, the participant cost would be equal to the cost differential between the two options.
   - New Construction (NC): in the case of a new building or system being constructed or installed, the participant cost would be equal to the difference between an energy efficient option and the defined baseline.

b) **Full Installed Cost:** is considered the cost of the efficient equipment including labour and removal costs (if applicable) of the existing equipment. The full installed cost basis is typically applied to the following scenarios:
   - Retrofit (RET) scenarios: in the case of residential attic insulation in a previously uninsulated attic, the full cost of the insulation, including installation, would be accounted for as the participant cost.
   - Early Retirement (ER) scenarios: is similar to the ROB scenario, but the equipment is replaced before the existing technology has reached the end of its useful life. The participant cost is often discounted by a “deferred replacement credit” that accounts for

the eventual replacement of the existing equipment with baseline equipment at the end of its remaining useful life[12].

Use: Participant costs should include all incremental costs that are directly related to the implementation of CDM, including costs associated with installation, de-installation, shipping and decommissioning. Participant costs may be incurred throughout the lifetime of a CDM measure. For example, O&M costs may be incurred on a regular basis over a CDM measure's EUL.[13] Please refer to section 4.1.1 to review the concept of EUL. In this case, costs must be discounted and inflation-adjusted. Participant costs should not be adjusted for the impact of incentives provided to a participating customer by a program administrator since the incentive costs are considered another component of a cost effectiveness analysis and treated differently for different metrics. Participant costs should be included in a cost effectiveness analysis at the measure level.

Special cases and examples of interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in section 7.

4.2.5 Incentive Costs

Description: Incentive Costs are costs that include cash incentives, payments for demand response services, upstream incentives, payments for studies, and in-kind contributions that the program administrator provides to participating customers, contractors, and trade allies to encourage the implementation of CDM by offsetting the incremental cost of efficiency (i.e., the participant costs).

Use: Any compensation resulting in a decrease in incremental cost to the program participant should be accounted for as an incentive cost even if payment is not received directly by the participant. For example, an appliance retirement program offers participants free pick-up of their old fridge or freezer. The cost to pick-up the appliance is estimated to be $100. Since the customer is directly receiving the benefit, the $100 is considered an incentive cost. In most

[12] For information on calculating a deferred replacement credit, please refer to the following memo. Rachel Brailove, John Plunkett, and Jonathan Wallach. "Retrofit Economics 201: Correcting Commons Errors in Demand-Side Management Cost-Benefit Analysis." Resource Insight, Inc. Circa 1990.

[13] Note that only *incremental* O&M costs should be counted. For example, if a participant installs a high-efficiency furnace that requires $100 worth of maintenance each year, but a standard furnace *also* requires $100 worth of maintenance each year, then incremental O&M costs are zero.

cases, incentive costs should be included in a cost effectiveness analysis at the measure level as incentives are typically associated with the implementation of a particular technology.

Special cases and examples of interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in section 7.

4.2.6 Program Costs

Description: Program Costs are the costs related to the program design, implementation, marketing, evaluation and administration of CDM, inclusive of fixed overhead costs. Incentive costs are not a component of program costs since they are considered another component of a cost effectiveness analysis and treated differently for different metrics.

Use: Program costs are often incurred at the program or portfolio level. Program costs can be incurred at the measure level as some program costs vary based on the number of measures implemented, otherwise known as variable costs (e.g., call centre labour for a program in which the installation of a measure requires participants call in and register). Program costs should be included in a cost effectiveness analysis at the level in which they are incurred. Costs incurred by a program administrator must be accounted for as either an incentive or program cost.

Special cases and examples on interpreting whether a cost is considered an incentive cost, program cost, or participant cost can be found in section 7.

4.2.7 Non-Energy Benefits (NEBs)/Externalities

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)

Description: NEBs represent improvements in the quality of life for program participants and/or society as a whole and are not typically captured by traditional cost effectiveness tests. Examples of NEBs include increased comfort, environmental improvements (i.e., reductions in carbon emissions, better air/water quality); reduction in health costs/improved health, water savings, and public/national security. NEBs and/or externalities vary depending on the perspective; some examples are noted in Figure 13.

Figure 13: Perspectives of Externalities

Customer Perspective	Utility Perspective	Societal Perspective
• Increased comfort • Improved air quality • Greater convenience	• Reduce the number of shutoff notices issued • Reduce bill complaints received	• Regional benefits in increased community health and improved aesthetics • Reduces reliance on imported energy sources, providing national security benefits

Use: Some NEBs are easier to quantify than others. When feasible, NEBs should be translated into a dollar value. However, in order to avoid the complex challenges associated with quantifying the benefits associated with non-energy benefits, a number of jurisdictions have implemented a fixed adder or adjusted discount rate to determine the cost effectiveness of CDM programs. Figure 14 presents a review of 13 jurisdictions' treatment of NEBs. The "$" heading indicates whether the NEBs are quantified into a monetary value when included in cost effectiveness tests.

Pursuant to the ministerial direction[14] provided to the IESO on October 23, 2014, a 15 per cent adder shall be included to the benefits calculated for the Total Resource Cost Test to take into consideration non-energy benefits associated with CDM programs..

[14] October 23, 2014 ministerial direction amending the March 31, 2014 direction regarding the 2015-2020 Conservation First Framework
http://powerauthority.on.ca/sites/default/files/news/MC-2014-2415.pdf

Figure 14: Jurisdictional Review of NEBs[15]

Jurisdiction	Low Income		All Programs		Notes
	Adder	$	Adder	$	
British Colombia	30%		15%	Y	Additional adjustment for emissions
California		Y	*In development*		
Colorado	25%		10%		Included at customer project level, not included at portfolio level
Iowa			10%		
Maine				Y	NEBs are not currently quantified, but are accepted
Massachusetts				Y	Include avoided costs of compliance to environmental regulations
Minnesota				Y	Reviewed by regulatory staff for reasonableness
New Hampshire			Y	Y	
New Mexico				Y	Emissions are the only non-energy benefits assessed
New York	Y	Y			Assessed at 3 levels of NEBs (0%, 50%, 100%)
Ontario			**15%**	**Y**	**TRC test only**
Oregon			10%	Y	Can include $ amount of NEBs as well if significant and quantifiable
Washington			10%	Y	Programs accepted under threshold cost effectiveness if there are many non-quantifiable NEBs
Vermont	15%		10%	Y	Some metrics quantified, others use an adder, NEBs are required in cost effectiveness evaluations

4.2.8 Tax Credits

Description: Tax credits capture any tax benefits at the municipal, provincial or federal level for which participants are eligible and may claim as a result of participating in CDM.

[15] Information is based on secondary literature, interviews, and consultant reports.

Use: Tax credits that can be attributed to the implementation of CDM may be included in the benefits, where appropriate. Tax credits can be used to calculate a PC and TRC ratio, but not for an SC ratio as they represent a transfer. The NTGR should be accounted for when assessing cost effectiveness from a TRC perspective.

4.2.9 Net Present Value (NPV) of Impacts

Concepts Required:

Effective Useful Life (4.1.1)
Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)
Net-to-Gross Ratio (4.1.6)
Line Losses (4.1.7)

Description: CDM resources are typically procured with a one-time payment in a given year and deliver a stream of peak demand and/or energy savings in the future. Determining the net present value (NPV) of the impacts or peak demand and energy savings achieved over the EUL of the measures associated with the implementation of CDM allows the costs and the benefits to be directly compared.

Use: Using the equation and guidance in section 4.1.5 to determine the net present value of the net energy savings at the generator level, where C_t would represent the peak demand or energy savings.

5 Calculation of Cost Effectiveness Metrics

The following section outlines how the components above are combined to evaluate cost effectiveness using the tests described in section 3. Figure 15 lists each component and indicates whether it is a benefit, cost, or transfer for each metric. Transfers have no net impact on the given test result.

Figure 15: Overview of Costs and Benefits

Component	TRC	SC	PAC	RIM	PC	LC
Avoided Electricity supply-side resource costs	*Benefit*	*Benefit*	*Benefit*	*Benefit*		
Other Supply-Side Resource Benefits	*Benefit*	*Benefit*		*Benefit*		
Bill Savings/Lost Revenue				*Cost*	*Benefit*	
Participant Costs	*Cost*	*Cost*			*Cost*	
Incentive Costs	*Transfer*	*Transfer*	*Cost*	*Cost*	*Benefit*	*Cost*
Program Costs	*Cost*	*Cost*	*Cost*	*Cost*		*Cost*
Non-Energy Benefits/Externalities	*Benefit*	*Benefit*				
NPV of Impacts						*Benefit*
Tax Credits	*Benefit*	*Transfer*			*Benefit*	

The result for each test may be expressed as a "net benefit" (Net B) in absolute dollars representing the difference between the present value (PV) of the inflation-adjusted benefits and the PV of the inflation-adjusted costs, or as a "benefit/cost ratio" (BC ratio) determined by dividing the PV of the inflation-adjusted benefits by the PV of the inflation-adjusted costs. The equations below demonstrate how the results of each test may be expressed.

$$Net\ B\ (\$) = PV(Benefits) - PV(Costs) \qquad BC\ Ratio = {PV(Benefits)}/{PV(Costs)}$$

This section will outline the calculation of the benefits and costs for each metric and specify whether each component of that calculation is net (i.e., takes into account the NTGR) or gross (i.e., does not take into account the NTGR). A few key considerations to note:

- Steps should be taken to avoid double counting of benefits and/or costs when calculating cost effectiveness metrics. For example, when savings from a behavioural program can also be attributed to an incentive program, the benefits should only be counted once.
- Costs associated with particular measure types must be treated consistently. It is *not* appropriate to treat costs differently to ensure the passing of a cost effectiveness test;
- Net peak demand and energy savings are used to calculate the components for all cost effectiveness tests with the exception of the PC test which is based on gross savings;
- Benefits should accrue for as long they persist over the EUL of CDM. O&M Costs should also be accounted for over the EUL of the measure(s);
- Incentives and program costs are always gross (i.e. include the costs associated with free-riders); and,
- Participant costs are always adjusted for NTGR in the TRC and SC tests but are not adjusted for NTGR in the PC test.

5.1 Total Resource Cost (TRC) Test

Components	
Benefits (B)	**Costs (C)**
• Avoided Supply-Side Resource Costs (net, generator level) • Other Supply-side Resource Benefits (net) • Tax Credits (net) • Non-Energy Benefits/Externalities (net)	• Participant Costs (net) • Program Costs (gross)

The TRC benefits and costs are calculated using the following equations and components:

$$Benefits = ASC + ORB + TC + \mathrm{NEB}$$

$$Costs = PTC + PRC$$

Where:

ASC = Avoided supply-side resource costs

ORB = Other supply-side resource benefits

TC = Tax credits

NEB = Non-energy benefits

PTC = Net participant costs

PRC = Program costs

Incentive costs are not included in the TRC test as they are a transfer from a program administrator to participating customers, and consequently do not impact the net benefit.

5.2 Societal Cost (SC) Test

Components	
Benefits (B)	**Costs (C)**
• Avoided Supply-Side Resource Costs (net, generator level) • Other Supply-side Resource Benefits (net) • Non-Energy Benefits/Externalities (net)	• Participant Costs (net) • Program Cost (gross)

The SC test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC + ORB + NEB$$

$$Costs = PTC + PRC$$

Where:

ASC = Avoided supply-side resource costs

ORB = Other supply-side resource benefits

NEB = Non-energy benefits

PTC = Participant costs

PRC = Program costs

The societal cost test may use an adjusted discount rate

5.3 Program Administrator Cost (PAC) Test

Components	
Benefits (B)	**Costs (C)**
• Avoided Supply-Side Resource Costs (net, generator level)	• Incentive Costs (gross) • Program Cost (gross)

The PAC test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC$$

$$Costs = IC + PRC$$

Where:

ASC = Avoided supply-side resource costs

IC = Incentive costs

PRC = Program costs

For the PAC Test, avoided supply-side resource costs only include avoided costs associated with the electricity system[16].

5.4 Ratepayer Impact Measure (RIM) Test

Components	
Benefits (B)	**Costs (C)**
• Avoided Supply-Side Resource Costs (net, generator level)	• Incentive Costs (gross) • Program Cost (gross) • Lost Revenue (net, end-user/customer level)

The RIM test benefits and costs are calculated using the following equations and components:

$$Benefits = ASC$$

$$Costs = IC + PRC + LR$$

Where:

ASC = Avoided supply-side resource costs

IC = Incentive costs

PRC = Program costs

LR = Lost revenue

[16] The PAC test only includes electricity system related costs because of the Ontario context. If a utility is responsible for other resources (e.g., natural gas), these costs would be included as well.

5.5 Participant Cost (PC) Test

Components	
Benefits (B)	**Costs (C)**
• Bill Savings (gross, end-user/customer level) • Incentive Cost (gross) • Tax Credits (gross)	• Participant Costs (gross)

The PC test benefits and costs are calculated using the following equations and components:

$$Benefits = (BS + IC + TC)$$

$$Costs = PTC$$

Where:

BS = Bill savings

TC = Tax credits

IC = Incentive costs

PTC = Participant Costs

5.6 Levelized Delivery Cost (LC)

Components	
Benefits (B)	**Costs (C)**
• NPV of impacts (peak demand or energy savings) (net, generator level)	• Incentive Costs (gross) • Program Costs (gross)

The LC metric is calculated differently than the other metrics. The equation and components used to calculate the LC metric is specified below:

$$LC\ Metric = \frac{(IC + PRC)}{NI}$$

Where:

IC = Incentive costs

PRC = Program costs

NI = NPV of impacts (peak demand or energy savings)

6 Cost Effectiveness Guidelines

This section provides additional guidelines and other information required to evaluate and use cost effectiveness metrics from various perspectives.

6.1 Assumptions

Cost effectiveness tests use many different assumptions that vary by jurisdiction. These assumptions include:

- Inflation Rate
- Discount Rates
- Base Year
- Line Losses
- Costing Period Definitions
- Avoided Supply Cost Tables
- Ratepayer Assumption Tables

Assumptions used to assess cost effectiveness in Ontario are specified in APPENDIX A and may be subject to change.

6.2 Screening Aggregation

Cost effectiveness evaluations can be performed at the measure, program, or portfolio level for a single year or multiple years and for energy efficiency and/or demand response. Performing cost effectiveness analyses at different levels of aggregation can be useful to determine the contribution of costs and benefits for the purposes of program design, re-design, and evaluation.

Different levels of aggregation will be appropriate for different situations. Figure 16 outlines a selection of screening aggregation examples with a description and some suggested uses.

Figure 16: Screening Aggregation

Measures	• Most benefits and costs can be easily defined or calculated at the measure level and in many cases *must* be calculated at the measure level to account for technology specific EULs and NTGRs. • Most incentive costs are incurred at the measure level. • Measure level cost effectiveness can be useful for comparing measures to each other.
Programs	• When assessing cost effectiveness at the program level, the costs and benefits within the program are aggregated, with the exception of costs incurred at the portfolio level. • It is appropriate to include program administration costs at this level if not already applied at the measure level. ○ An example of program costs incurred at the program level is customer segment specific marketing efforts that do not focus on a particular program such as a radio marketing campaign to direct residential customers to a website containing all residential programs. • Program level cost effectiveness can be useful for comparing program performance year over year and for assessing the performance of different segments. • Evaluation typically occurs at the program level aggregation.
Portfolios	• Cost effectiveness at the portfolio level should account for all costs and benefits associated with the design, delivery, and implementation of CDM. • This may include some overhead costs that were not previously allocated to a measure or program. ○ An example of program costs incurred at the portfolio level is overhead administration costs such as the payroll and office facilities of the program administrator. • Portfolio level cost effectiveness can be useful for assessing year over year performance of the CDM portfolio, for assessing the overall net benefit of CDM by a program administrator, and monitoring the impacts of a change to the portfolio on overall net benefits.

Energy Efficiency (EE) and Demand Response (DR)	• CDM programs and portfolios may consist of both EE and DR resources. EE resources are CDM programs that target energy conservation measures or actions; whereas DR resources are CDM programs that target peak demand reduction.[17] • The IESO's Protocols for Estimating Load Impacts Associated with Demand Response Resources in Ontario[18] and the associated cost effectiveness tool should be used when assessing the cost effectiveness of DR resources. • The cost effectiveness components (i.e., costs and benefits) from a DR cost effectiveness assessment may be aggregated with the components of an EE cost effectiveness assessment at the appropriate level (i.e., program, or portfolio) to determine the aggregate cost effectiveness.
Single Year	• Provides an instantaneous snapshot of cost-effectiveness. • Useful for comparing cost effectiveness of CDM from year to year but may understate benefits relative to costs, since benefits tend to accrue evenly across an EUL whereas costs are often mostly accrued in the first year of the EUL.
Multiple Years	• Provides a broader view point, and is useful for determining overall cost effectiveness for CDM which may have variable savings and costs year to year. • Some programs, and/or portfolios may have extensive up-front costs (e.g., administration, marketing, capability building) and as they mature, the fixed costs tend to diminish and are able to more cost effectively achieve greater savings. ○ In this instance, a single year snap shot assessment would understate cost effectiveness in the early stages of the program, or portfolio (e.g., appear less cost effective), and overstate cost effectiveness in the later stages. • A multi-year perspective typically provides a more holistic depiction of the long-term cost-effectiveness of the program. • This is also true for programs, and portfolios with long lead times.

As shown in Figure 17, not all measures or programs will produce a positive net benefit. However when a program or portfolio of programs as a whole is assessed, the benefit could be positive.

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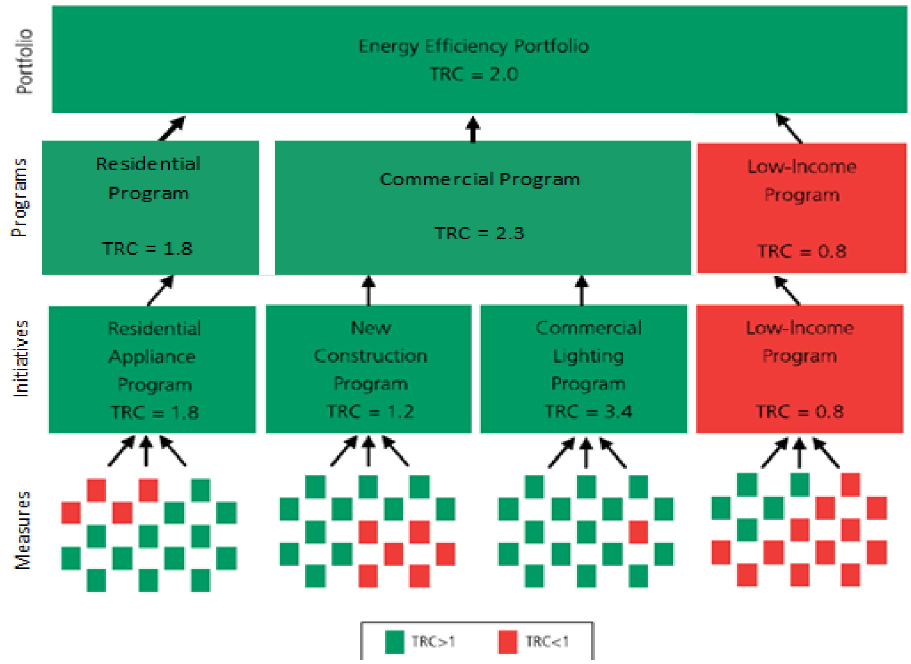
[17] EE resources may also deliver peak demand reductions and DR resources may also deliver energy savings, but these are not the driving force behind the program design.

[18] Available at: http://www.powerauthority.on.ca/benefits/evaluation-measurement-and-verification

Figure 17: Illustrative Example of Portfolio TRC[19]



When calculating cost effectiveness for any level of aggregation, it is not appropriate to simply combine the outputs (i.e., the net benefits or cost benefit ratios). Instead, the inputs (i.e., the costs and benefits themselves) must be re-calculated with consistent assumptions and then aggregated. The steps below outline this process for a multi-year cost effectiveness analysis.

[19] Adapted from: National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. Energy and Environmental Economics, Inc. and Regulatory Assistance Project.

Concepts Required:

Real vs. Nominal (4.1.2)
Discount Rates (4.1.3)
Base Year (4.1.4)
Net Present Value (4.1.5)

Step 1: Ensure Consistency across Assumptions

Align the assumptions used to calculate the NPV of the cost and benefit components (i.e., base year, real vs. nominal, inflation rate, and discount rate). Please refer to section 4.1.5 to review this concept. It is not necessary to modify the EUL or NTGR assumptions used within each year of a multi-year analysis. The EUL and NTGR should align with the program year as these components can change year to year.

Step 2: Aggregate Components

Sum each cost and benefit component re-calculated with consistent assumptions across all levels of aggregation (e.g., all program years).

Step 3: Recalculate Metrics

Re-calculate the net BC, BC ratio, and LC metric with the aligned and summed benefit and cost components.

6.3 Comparing Supply-Side Resources

In general, cost effectiveness tests and the levelized cost metric provide a basis for not only comparing CDM measures, programs, or portfolios with each other, but also for comparing CDM to the cost of supply-side resources.

Each cost effectiveness metric includes different costs (and benefits) and may not provide a full perspective when comparing to supply-side resources. It is important to understand all inputs of both CDM and supply-side metrics and the implications of comparing them directly. Some considerations include: whether a resource is base load or peaking, how long a resource is available, and the extent to which it can or cannot be dispatched.

With the exception of the PC test, all tests provide an estimate of the benefit of avoided supply-side resource costs. Typically, supply-side assessments include costs similar to a PAC test or LC metric (i.e., the costs incurred by a program administrator) and do not typically include costs incurred by participants, which are included in the TRC, SC, and PC.

6.4 Varying Avoided Costs

As mentioned in previous sections, avoided supply-side resource costs account for:

- Variable generation costs including the cost of fuel;
- Operating and maintenance costs for power plants; and
- Avoided generation, transmission and distribution infrastructure costs due to reduced peak demand.

Avoided supply-side resource costs translate energy savings and peak demand reductions into a dollar value. The assumptions used in the calculation of this dollar value may vary over time. If assumptions change, a challenge arises on how results of the tests can be compared. It is important to be aware of the underlying assumptions used to develop to the avoided costs and follow the policies and accepted assumptions specified in APPENDIX A and this Guide.

7 Special Cases/Examples

This section provides examples and special cases where the interpretation of the guidelines associated with cost components is not straight forward. In many cases, the details of the program design will provide guidance towards how costs should be treated and how changes in program design can impact the treatment of the costs. When interpreting costs, it is important to consider the implications on each test and to follow the principles below:

- Be consistent with the treatment of costs and benefits year over year, where appropriate, to ensure that results are comparable;
- Steps should be taken to avoid double counting of benefits and/or costs when calculating cost effectiveness metrics by considering the impact of the categorization for each metric, for example, when costs are considered program costs they cannot also be participant costs as that would result in the same costs being double counted in the TRC test; and,
- Costs incurred by a program administrator must be accounted for as either an incentive or program cost.

This is not intended to be an exhaustive list of all possible areas of ambiguity, but provides some illustrative examples of how to interpret the definitions presented in this Guide.

7.1 Appliance Pick-up Measures

Case	In an appliance pick-up program, the participant receives a free appliance pick-up paid for by the program administrator.
Treatment	The cost of appliance pick up and decommissioning should be treated as both a participant cost and an incentive cost.
Reasons	The pick-up and decommissioning costs associated with these measures should be accounted for as participant costs since these costs are directly related to CDM implementation. The same costs should also be accounted for as incentive costs since the cost to the participating customer is completely offset by the program administrator even though payment is not received directly by the participant.
Example	If pick-up and decommissioning costs are $100, these costs should be accounted for as $100 participant costs and $100 incentive costs. The $100 participant cost should be included in the TRC, SC, PC, and LC. The $100 incentive cost should be included in the PAC, RIM, and PC. Note that the $100 appears on both the benefit and cost side of the PC test delivering a net impact to the customer of $0.

7.2 In-Home Display (IHD) Measures

Case	An IHD is provided free of charge to a participant by the program administrator.
Treatment	The equipment, installation and O&M costs of the IHDs should be treated as both participant costs and incentive costs.
Reasons	The cost for IHD equipment, O&M and installation of devices should be accounted for as participant costs since these costs are directly related to CDM implementation. Since these costs are all paid by the program administrator, they should also be accounted for as an incentive cost.
Example	If equipment, O&M and installation costs are $400 and there is an additional $25 participation bonus paid to the customer, these costs should be accounted for as $400 participant costs and $425 incentive costs. The $400 participant cost should be included in the TRC, SC, and PC. The $425 incentive cost should be included in the PAC, RIM, PC, and LC. Note that the $400 appears on both the benefit and cost side of the PC test delivering a net impact to the customer of $25.

7.3 Direct Install Measures

Case	The cost of replacing and/or installing energy efficient equipment is covered by a direct install program. The participant's costs are covered by the program administrator up to a certain cap.
Treatment	All equipment and installation costs should be treated as participant costs. All equipment and installation costs, up to the program cap (if applicable), should be treated as incentive costs.
Reasons	All incremental costs associated with equipment and installation should be accounted for as participant costs even if participant costs exceed a capped incentive level. The incentive transferred to a participating customer should be accounted for as incentive costs even if not received directly by the participant.
Example	If equipment and installation costs are \$1,800 and the incentive level is capped at \$1,500, these costs should be accounted for as \$1,800 participant costs and \$1,500 incentive costs. The \$1,800 participant cost should be included in the TRC, SC, and PC. The \$1,500 incentive cost should be included in the PAC, RIM, PC, and LC. Note that \$1,500 appears on both the benefit and cost side of the PC test delivering a net impact to the customer of \$300.

7.4 Midstream and Upstream Incentives

Case	Midstream incentives are costs incurred by a program administrator to provide assistance to retailers, distributors or dealers to promote CDM measures to their customers. Upstream incentives are incentives that program administrator provide as assistance to manufacturers to promote CDM to downstream consumers.
Treatment	If all or part of the midstream and/or upstream incentive provided to manufacturers, retailers, distributors or dealers is directly passed on to consumers through a price discount then that amount should be accounted for as an incentive cost. If all or part of the midstream and/or upstream incentive provided to manufacturers, retailers, distributors or dealers is used in the promotion and marketing of CDM, then the midstream and/or upstream incentive should be treated as a program cost. If the allocation of the midstream and/or upstream incentive between price discount and marketing/promotion is unknown it should be accounted for according to policy direction.
Reasons	The discount passed on to consumers reducing the incremental cost to the participant should be accounted for as an incentive cost. If costs are used for marketing and promotion they should be accounted for as a program cost as the monetary benefit is not passed on to participants.
Example	A retailer is given $25/unit to encourage participation in a CDM program. The retailer uses $10/unit to promote CDM and $15/unit is used to reduce the price of CDM measures. The retailer sells 100 units. The $1,000 ($10/unit x 100 units) used to promote the program should be included in the TRC and SC test as a program cost. The $1,500 ($10/unit x 100 units) passed to the customer should be included in the PC test as an incentive cost. The full $2,500 ($25/unit x 100 units) should be included in the LC, RIM, and PAC.

7.5 Performance Incentives

Case	A third party program administrator is delivering a particular CDM program and is provided with a performance incentive for achieving a certain amount of peak demand and energy savings.
Treatment	Costs associated with performance incentive payments should be treated as program costs. Performance incentives should be included in cost effectiveness assessments in the level in which they occur (i.e., measure, program, portfolio).
Reasons	Performance incentive payments are not directly transferred to customers and are not related to the incremental cost of implementing CDM, therefore they should be considered program costs. However, if the performance incentive is being used by the third party to increase the standard incentives provided to participants, then the performance incentives should be considered as incentive costs.
Example	A third party program administrator is delivering a particular CDM program and is provided with a $100 performance incentive for achieving a certain amount of overall peak demand and energy savings. The program administrator does not pass this incentive on to participants. The $100 should be included in the TRC, SC, RIM, LC, and PAC as a program cost and should not be included in the PC test.

7.6 Training

Case	A program administrator implements a capability building program to increase technicians' knowledge and/or expertise in the installation of air conditioners to support an efficient air conditioning program.
Treatment	Payments related to the training of technicians should be considered a program cost and should be accounted for at the level the training is impacting. In this case, the training directly impacts an program and thus can be included at the program level.
Reasons	The cost of the training is not offsetting the cost of implementing CDM for the participant, nor is the cost of training part of the incremental cost of the efficient technology (the cost of the CDM has not changed). Since costs incurred by a program administrator must be either an incentive or program cost, training is considered a program cost.
Example	A program administrator pays \$2,000 for technicians to undergo training to more efficiently install air conditioners. As a result, air conditioners installed through the efficient air conditioning program save more per unit. The \$2,000 should be included as program costs in the TRC, PAC, SC, RIM, and LC and should be assessed as part of the costs for the air conditioning program. The \$2,000 should not appear in the PC test as this cost is not transferred to the participant.

7.7 Engineering Studies

Case	Funding for engineering studies is provided to participants to assist them in identifying energy efficiency opportunities (typically within a given price cap).
Treatment	Payments related to engineering studies should be considered a participant cost. Any payments made to account for the cost of the engineering study up to the cap should be considered an incentive cost.
Reasons	In absence of the program, the customer would have to pay for the study. The program administrator is paying up to a certain cap for the cost of the study and is thus partially offsetting the cost to the participant.
Example	A participant completes a $1,000 study that is 80% funded by the program administrator. The $1,000 should be included as participant costs in the TRC and SC. $800 should be included in the PAC, LC, and RIM test as an incentive costs. The $1,000 should appear in the PC test on the cost side as a participant cost and $800 incentive should appear on the benefit side delivering a net impact from the participant's perspective of $200.

7.8 Home Energy Report

Case	A utility works with a third party to produce home energy reports for a specified population of customers. The customers would not otherwise have access to the home energy reports without the utility intervention. Customers do not incur a cost and can opt out if desired.
Treatment	The cost of the home energy reports would be considered a program cost[20].
Reasons	The program administrator incurs the total cost associated with the home energy reports. The home energy reports would not otherwise be available to the customer and thus are not considered a participant cost. Typically, savings from these programs are behavioural and therefore carry no incremental cost to the participant.
Example	The service provider produces home energy reports for utility customers. The program administrator is charged $18,000/year to receive these reports. The $18,000 would be included as a program cost in the TRC, SC, PAC, LC, and RIM tests. The PC test would not contain any costs associated with the home energy reports.

[20] If this service is directly accessible to the customer without utility intervention at a cost to the customer, these costs would be treated similar to an engineering study (see section 0)

8 Acronym List

ASC	Avoided supply-side resource costs
BC	Benefit Cost
BS	Bill Savings
CDM	Conservation And Demand Management
DR	Demand Response
Dx	Distribution System
EE	Energy Efficiency
ER	Early Retirement
EUL	Effective Useful Life
FR	Free Ridership
IC	Incentive Costs
IE	Interactive Effects
IHD	In-Home Display
kW	Kilowatt
kWh	Kilowatt Hour
LC	Levelized Delivery Cost
LLF	Line Loss Factor
LR	Lost Revenue
LUEC	Levelized Unit Energy Cost
ME	Market Effects
MW	Megawatt
MWh	Megawatt Hour
NC	New Construction
NDR	Nominal Discount Rate
NEBs	Non-Energy Benefits
NI	Net Impacts (Peak Demand And Energy Savings)
NPV	Net Present Value
NTGR	Net to Gross Ratio

O&M	Operations And Maintenance
ORB	Other Resource Benefits
PAC	Program Administrator Cost
PC	Participant Cost
PRC	Program Costs
PTC	Net Participant Costs
PV	Present Value
RDR	Real Discount Rate
RE	Rebound Effect
RET	Retrofit
RIM	Rate Impact Measure
ROB	Replace On Burnout
RR	Realization Rate
RUL	Remaining Useful Life
SC	Societal Cost
SO	Spillover
T&D	Transmission And Distribution
TC	Tax Credits
TRC	Total Resource Cost
Tx	Transmission System

APPENDIX A

Use to convert real dollars to nominal dollars.

Inflation Rate	2.00 %

Use to calculate the NPV of costs and benefits.

Cost Effectiveness Metric	**Discount Rates (Real)**
Discount Rate	4.00 %

Use to calculate the NPV of costs and benefits.

Base year	2014

Use to calculate savings at the generator level.

Line Losses	**Percentage**
Average Distribution System Losses	4.20 %
Average Transmission System Losses	2.50 %

Costing Period Definitions

Table 1: Seasonal Periods

Season	Months Included
Winter	December – March
Summer	June – September
Shoulder	April, May, October & November

Table 2: Time of Use Periods

	Winter	Summer	Shoulder
On-Peak	0700 – 1100 and 1700 – 2000 weekdays (602 Hours)	1100 – 1700 weekdays (522 hours)	None
Mid-Peak	1100 – 1700 and 2000 – 2200 weekdays (688 hours)	0700 – 1100 and 1700 – 2200 weekdays (783 hours)	0700 – 2200 weekdays (1,305 hours)
Off-Peak	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,614 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)	0000 – 0700 and 2200 – 2400 weekdays; All hours weekends and holidays (1,623 hours)

Note: Numbers are the daily hours for the various periods

Avoided Supply Costs

The following avoided supply costs are an output based on the resource mix defined in Ontario's Long-Term Energy Plan[21]

Year	Avoided Cost of Energy Production 2014 $/MWh by TOU Period								Avoided Capacity Costs 2014 $/kW-yr		
	Winter			Summer			Shoulder		At System Peak		
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Generation Capacity	Transmission	Distribution
2015	$46.53	$43.38	$37.76	$33.65	$38.83	$31.87	$47.55	$40.77	-	$3.83	$4.73
2016	$36.08	$31.88	$31.81	$31.39	$36.65	$29.55	$42.24	$35.94	-	$3.83	$4.73
2017	$40.97	$34.96	$28.72	$27.98	$38.38	$30.74	$38.39	$33.51	$162.15	$3.83	$4.73
2018	$41.97	$35.82	$32.69	$25.14	$36.66	$29.75	$31.77	$26.98	$162.15	$3.83	$4.73
2019	$40.71	$38.57	$34.37	$37.43	$43.06	$34.67	$36.72	$32.90	$162.15	$3.83	$4.73
2020	$39.88	$36.86	$34.93	$36.75	$41.06	$33.80	$33.89	$31.23	$162.15	$3.83	$4.73
2021	$47.28	$45.16	$44.50	$43.91	$48.41	$44.82	$40.19	$38.99	$162.15	$3.83	$4.73
2022	$48.33	$47.47	$45.76	$42.48	$46.39	$43.93	$40.97	$39.27	$162.15	$3.83	$4.73
2023	$42.94	$42.84	$42.41	$41.86	$46.18	$42.58	$35.85	$33.64	$162.15	$3.83	$4.73
2024	$43.28	$42.02	$40.73	$41.90	$46.17	$41.61	$34.45	$32.84	$162.15	$3.83	$4.73
2025	$44.37	$43.42	$42.15	$40.28	$43.89	$39.21	$36.29	$36.05	$162.15	$3.83	$4.73
2026	$41.26	$40.08	$39.69	$39.77	$44.01	$38.82	$34.52	$32.62	$162.15	$3.83	$4.73
2027	$44.01	$41.72	$41.89	$39.32	$42.89	$38.96	$41.17	$39.10	$162.15	$3.83	$4.73
2028	$43.82	$42.88	$40.20	$41.56	$45.57	$40.75	$36.94	$33.86	$162.15	$3.83	$4.73
2029	$45.32	$43.69	$41.06	$40.96	$44.43	$40.30	$39.97	$39.19	$162.15	$3.83	$4.73
2030	$44.18	$43.17	$41.25	$42.10	$45.83	$39.88	$36.33	$34.50	$162.15	$3.83	$4.73
2031	$43.53	$42.40	$40.04	$40.95	$43.95	$38.57	$38.45	$37.29	$162.15	$3.83	$4.73
2032	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73
2033	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73
2034	$41.96	$40.90	$39.24	$40.56	$43.38	$38.15	$36.42	$33.61	$162.15	$3.83	$4.73

[21] Achieving Balance - Ontario's Long-Term Energy Plan – December 2013 (http://www.energy.gov.on.ca/en/ltep)

Ratepayer Assumptions

Year	Electricity	Natural Gas	Water	Propane	Heating Oil
	2014 $/kWh	2014 $/MMBtu	2014 $/L	2014 $/L	2014 $/L
2015	0.12	0.17	0.000004262	0.39	0.46
2016	0.13	0.17	0.000004262	0.39	0.46
2017	0.13	0.17	0.000004262	0.39	0.46
2018	0.13	0.17	0.000004262	0.39	0.46
2019	0.13	0.17	0.000004262	0.39	0.46
2020	0.13	0.17	0.000004262	0.39	0.46
2021	0.12	0.17	0.000004262	0.39	0.46
2022	0.12	0.17	0.000004262	0.39	0.46
2023	0.12	0.17	0.000004262	0.39	0.46
2024	0.12	0.17	0.000004262	0.39	0.46
2025	0.12	0.17	0.000004262	0.39	0.46
2026	0.12	0.17	0.000004262	0.39	0.46
2027	0.12	0.17	0.000004262	0.39	0.46
2028	0.12	0.17	0.000004262	0.39	0.46
2029	0.12	0.17	0.000004262	0.39	0.46
2030	0.12	0.17	0.000004262	0.39	0.46
2031	0.12	0.17	0.000004262	0.39	0.46
2032	0.12	0.17	0.000004262	0.39	0.46
2033	0.12	0.17	0.000004262	0.39	0.46
2034	0.12	0.17	0.000004262	0.39	0.46
2035	0.12	0.17	0.000004262	0.39	0.46
2036	0.12	0.17	0.000004262	0.39	0.46
2037	0.12	0.17	0.000004262	0.39	0.46
2038	0.12	0.17	0.000004262	0.39	0.46
2039	0.12	0.17	0.000004262	0.39	0.46
2040	0.12	0.17	0.000004262	0.39	0.46
2041	0.12	0.17	0.000004262	0.39	0.46
2042	0.12	0.17	0.000004262	0.39	0.46
2043	0.12	0.17	0.000004262	0.39	0.46
2044	0.12	0.17	0.000004262	0.39	0.46
2045	0.12	0.17	0.000004262	0.39	0.46
2046	0.12	0.17	0.000004262	0.39	0.46
2047	0.12	0.17	0.000004262	0.39	0.46
2048	0.12	0.17	0.000004262	0.39	0.46
2049	0.12	0.17	0.000004262	0.39	0.46
2050	0.12	0.17	0.000004262	0.39	0.46

Revision History

1. Sep 22, 2014 – Label on Avoided Cost of Energy Production table corrected. Summer and Winter labels swapped. Pg. 58.
2. October 27 -15 per cent adder for non-energy benefits inserted in section 4.2.7.

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ED INTERROGATORY 19

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

19. The IESO’s consultant, John Todd, concluded with respect to the TWh conservation targets that “Appropriate annual milestones consistent with these long-term targets should be identified for reporting in the Scorecard.” What annual milestones does the IESO believe would be appropriate? Please explain and justify any response.

RESPONSE

The IESO does not believe that annual TWh conservation targets would be appropriate for the purposes of the regulatory scorecard. The IESO’s role with respect to conservation has, and is expected to continue to evolve within the spectrum of administering, designing and delivering conservation programs, which an annual target may not reflect. In addition, the progress of the Conservation First Framework, including targets, will be looked at as part of the Mid-term Review.

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ED INTERROGATORY 20

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

20. In its May 2017 report, *Ontario-Quebec Interconnection Capability: A Technical Review*, the IESO described a number of options which could increase Ontario's capacity to import electricity from Quebec using the existing interties and by building a new 2,000 MW intertie (see pages 18 to 27). Please state the IESO's dates for the completion of cost-benefit analyses with respect to each of these options.

RESPONSE

20. The IESO is of the view that this is outside of the scope of a regulatory scorecard. In an effort to be of assistance to parties, the IESO provides the following additional context.

    The IESO does not have a date for the completion of cost-benefit analyses with respect to each of the options identified in the report. The May 2017 report, *Ontario-Quebec Interconnection Capability: A Technical Review* was prepared to address intertie and transmission capability only. The report did not address aspects such as the characteristics and cost of the capacity and energy resources in each jurisdiction, current and forecast demand/supply conditions, nor market-based alternatives, which are important inputs into assessing the value, or cost-benefit, of each of the options identified in the report.

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ED INTERROGATORY 21

Issue 5.1 Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

Reference for the following interrogatories: Exhibit C, Tab 1, Schedule 1, p. 4

21. In its *Ontario-Quebec Interconnection Capability* report, the IESO described a number of options which could increase Ontario's capacity to import electricity from Quebec. Would the IESO object to the inclusion of the completion of cost-benefits analyses with respect to these options as one of its Regulatory Scorecard's metrics? If yes, please fully outline and explain the IESO's objections.

RESPONSE

21. The IESO is of the view that metrics linked to a cost-benefit analysis of options for increasing Ontario's capacity to import more electricity from Quebec are not appropriate for inclusion in the IESO's scorecard.

    As stated in the settlement proposal in the IESO's 2016 revenue requirement submission, the scorecard is intended to "be a tool for the Board and intervenors to use in evaluating the IESO's proposed expenditure and revenue requirement". The IESO is of the view that completion of cost-benefits analyses with respect to Ontario's capacity to import electricity from Quebec would not aid in evaluating the IESO's proposed expenditure and revenue requirement and is not an indicator of the cost-effectiveness of IESO activities.

    In addition, evaluating Ontario's interties with Quebec is one of many system studies that the IESO engages to fulfil its object to conduct system planning.

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SEC INTERROGATORY 20

5.0 Commitments from OEB Decisions

Issue 5.1

Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

[C1-1-1, Attach 1, p.33] The Elenchus Report states "One stakeholder also suggested that one or more metrics pertaining to compliance with the market rules would be of greater value. The IESO, however, is concerned that it would be difficult to do so without violating confidentiality rules around investigations and disclosure of outcomes. Given the complexity of investigations and the nature of settlement, classifying the outcomes would be problematic".

a. Please explain fully the IESO's concern regarding potential high-level metrics regarding market rules compliance and investigations.

b. Please explain how the IESO measures compliance with the market rules.

c. Please explain how the IESO's Market Assessment and Compliance Division measures its own performance.

RESPONSE

a) The IESO's mandate is to support the objectives of the Electricity Act in many respects, including the promotion of an efficient and reliable electricity market and power grid. These goals are furthered by fostering compliance with Ontario market rules and North American reliability standards through enforcement and other measures. The IESO's Market Assessment and Compliance Division (MACD) is a ring-fenced business unit which conducts the bulk of these activities. MACD's initiatives include a wide range of activities including compliance (such as education, outreach, rule interpretive guidance) and enforcement (such as enforcement of rule provisions allowing for direct market payment recoveries to investigations of conduct). Some of these activities lead to findings of non-compliance and the issuance of financial penalties and other sanctions. The objective of MACD is to foster compliance with the Market Rules and reliability standards using the most effective means possible, with compliance investigations often reserved for instances where more effective means are unavailable, and where the impact on the market or reliability is most significant. Findings of non-compliance are publicly available on the IESO website as are a number of settlement agreements which do not always include a finding of non-compliance. Investigations and execution of payment recovery authorities under the market rules are confidential by rule. Matters which are resolved by way of negotiated settlement are also usually confidential, as a matter of legal practice.

In summary, the question asks about metrics related to “compliance and investigations”. First, compliance is fostered by many means, investigations just being one process or tool to that end. As a result, it is unclear what kind of metrics would be relevant. Second, investigations are confidential by rule. Only descriptions of outcomes are permitted under the market rules.

b) Like many enforcement agencies, the IESO uses a risk-based approach related to compliance with Market Rules and Reliability Standards to guide the identification of events of interest. Market activity is monitored daily for events which may have a significant actual or potential market (financial) or reliability impact. These events receive additional study and, if appropriate, escalation for further evaluation. In this way, MACD has tuned its enforcement activities to focus on the most material events which it could possibly address within its resource set. Material events are those that, if they were the result of a breach of the market rules or reliability standard, would most significantly undermine the objective of the market rules and/or standard, which is to govern the IESO-controlled grid and to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and ancillary services in Ontario.

MACD supplements this market monitoring activity by performing a limited range of in-depth audits of market participants’ compliance with reliability standards. Other business units also execute a range of other processes aimed at measuring whether participants are within compliance of the rules and standards.

The principal method by which MACD assesses its performance is on a value-for-money basis. For example, in 2016, MACD assessed that its functions, rule enforcement and market design recommendations, had generated a minimum of $300 million of net ratepayer value (at a cost of ~$50M) from market opening in terms of the impact on ratepayers. This was mainly by way of monies returned to the market, or the curtailment or elimination of wasteful market programs. This reflects MACD’s principal role in overseeing the market.

c) Its role in enforcing reliability standards has been measured more as contributory to the IESO’s broader efforts in ensuring reliability in Ontario, as the outcomes and preventative measures are not as easily monetized. There have been no major reliability events in Ontario during this time period.

SEC INTERROGATORY 21

5.0 Commitments from OEB Decisions

Issue 5.1

Is the IESO's proposed Regulatory Scorecard appropriate?

INTERROGATORY

[C1-1-1, Attach 1, p.42] Please complete the proposed scorecard showing metrics calculated on an annual basis for 2015 and 2016.

RESPONSE

Please refer to the response to Energy Probe Interrogatory 17 at Exhibit I, Tab 5.0, Schedule 5.17 and page 38 of Exhibit C-1-1, Attachment 1 regarding Reporting Data for Prior Years.

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