Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Integrated Planning Requirements – Part 1: Regional Infrastructure Planning

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July 24, 2013

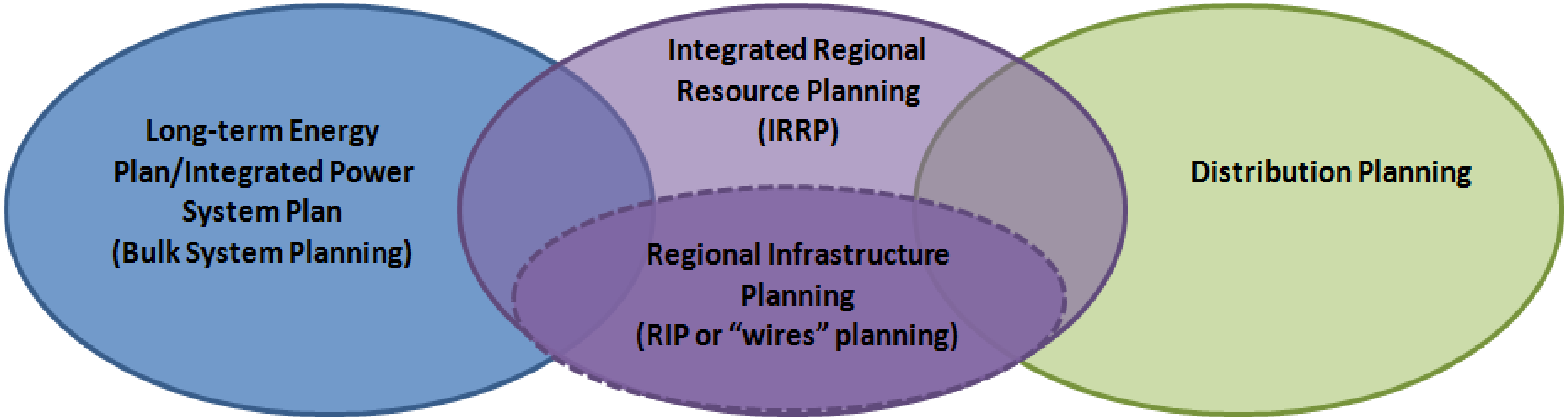
Today's Presentation

- Objectives of Regional Infrastructure Planning
- Regional Planning in Context
- Description of Regional Planning process
- Key features of Regional Infrastructure Planning process
- OPA and Transmitter deliverables
- Key LDC Obligations
- Transition and Implementation
- Highlights of Proposed Code Amendments including documentation to support applications

Objectives of Regional Infrastructure Planning

- More structured & transparent approach to Regional Planning
- Timely implementation of required regional infrastructure
- Planning & assessment to support identification & implementation of ‘optimal’ solutions
- Coordinated regional planning to ensure cost effective and efficient wires expansion
- Coordinate with OPA IRRP process to account for integrated (i.e. non-wires) solutions
- Documentation to support LDC rate applications and transmitter rate and LTC (s.92) applications

Regional Planning in Context



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

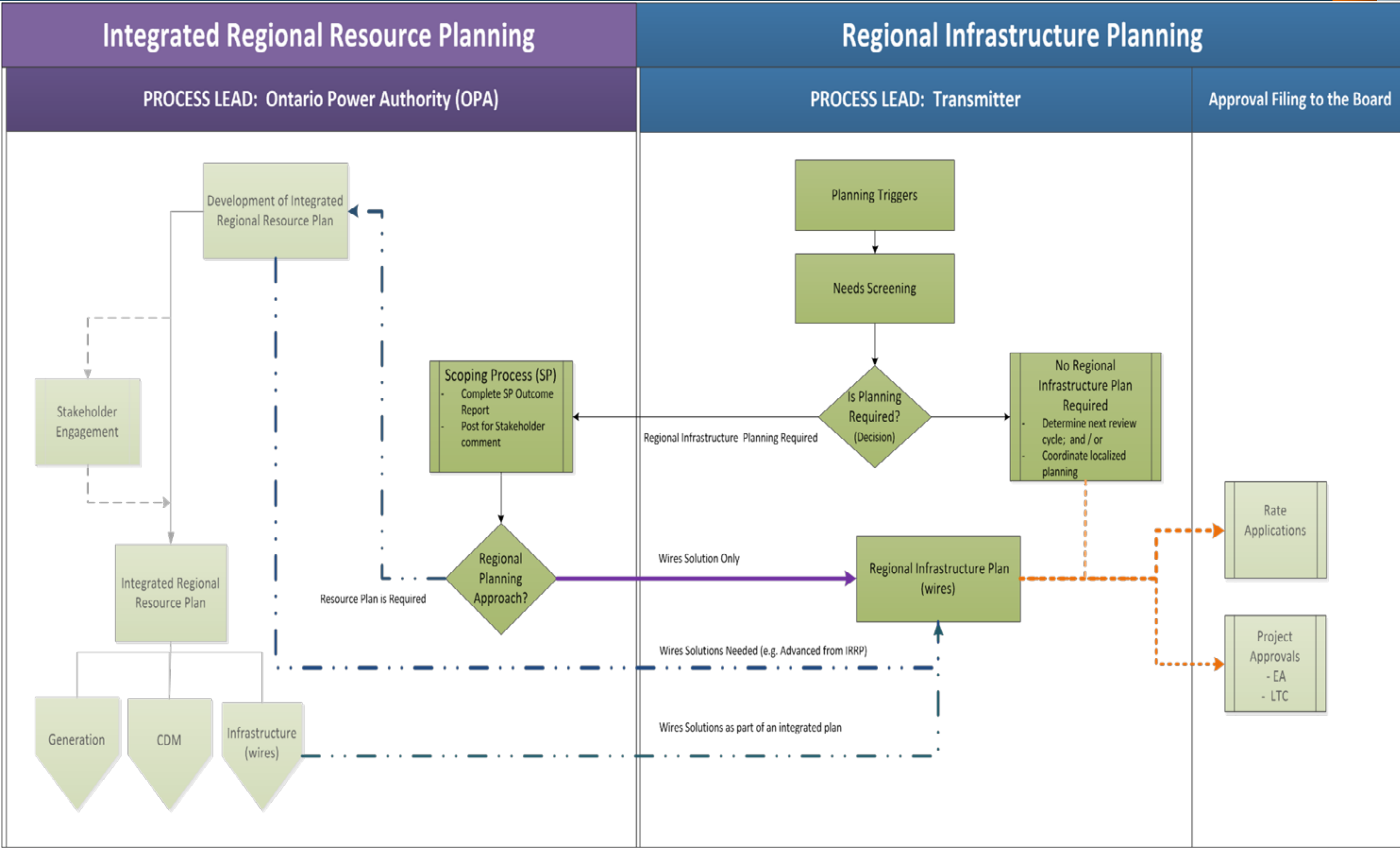
- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

What is Regional Infrastructure Planning?

- **Regional Infrastructure Planning:**
  - Focuses on planning of ‘wires’ (mainly Tx, some Dx)
  - Coordinates *transmission connection* (i.e., supply) facilities to LDCs and other customers
  - Where needs driven by regional considerations, also coordinates planning of wires facilities at *bulk transmission* and *distribution* levels

- **Regional Infrastructure Planning does <u>not</u> plan:**
  - Bulk transmission facilities (except where such facilities driven by regional needs or provide alternative solution)
  - Distribution facilities (except where such facilities driven by regional needs)
  - Resources (i.e. Generation, CDM) at all levels – bulk, regional and distribution

The Regional Planning Process in Ontario



Regional Infrastructure Planning features

- Structured approach with 21 electrically based regions
  - PPWG Report includes Appendix 4 listing LDCs in each region
- With 3 possible outcomes, RIP provides for appropriate level of planning coordination:

  1. No regional coordination needed
  2. Regional coordination of wires only
  3. Regional coordination of resources (CDM & generation) & wires
- *Increased transparency:* plan scoping, development, consultation, posting documents
- Recognizes need for close coordination with OPA's IRRP process

Transmitter Key Deliverables

- **<u>Intermediate Products</u>**
  - Needs Assessment Report
    - Determines if regional planning needed and, if so, identifies LDCs to be active participants

- **<u>Final Products</u>**
  - Annual Report: RIP Status Updates to Board
  - RIP Planning Status Letter
  - Regional Infrastructure Plan
    - Recommended ‘wires’ solutions
    - Implementation plan
    - Project timelines and monitoring

OPA Key Deliverables

- **Intermediate Products**
  - Scoping Process Outcome Report
    - Identifies planning approach – IRRP or RIP only – and rationale behind approach
    - Will be posted for stakeholder feedback

- **Final Product**
  - Integrated Regional Infrastructure Plan (IRRP)
  - Will be posted for stakeholder feedback before finalized
  - Final IRRP to transmitter on need for "wires" solutions for RIP
  - If IRRP not finalized, OPA still required to identify to transmitter "near term" (i.e., 0 – 5 years) wires solutions required for RIP
    - Implementation plan
    - Project timelines and monitoring

What does this mean for LDCs?

- Provide requested information
  - All LDCs in region to provide forecast information to lead Transmitter (for 'Needs Assessment')
  - Provide any additional forecast information underlying forecasts requested by OPA / Transmitter
    - Investment plans, relevant community energy plans, future station requirements, DG, CDM plans
- *Needs Assessment:* Transmitter will identify LDCs in region to remain involved in process (if regional planning needed)
- Scoping Process (led by OPA)
  - RIP process (led by Transmitter) and/or IRRP process (led by OPA)
  - LDCs to be involved in both processes, as required
- As an active participant in RIP/IRRP processes, LDCs will be able to:
  - Identify potential distribution solutions in their territory
  - Provide input on investments that affect them
- Resulting documents to be used by LDCs to support applications

RIP Transition and Implementation

- 4 years to complete first cycle

- Regions prioritized into 3 groups based on expected need
  - ✓ Group 1 - (underway – 2014)
  - ✓ Group 2 - (2014 – 2015)
  - ✓ Group 3 - (2016 – 2017)

- Group 1 Regions have planning activities underway for some or all parts of region

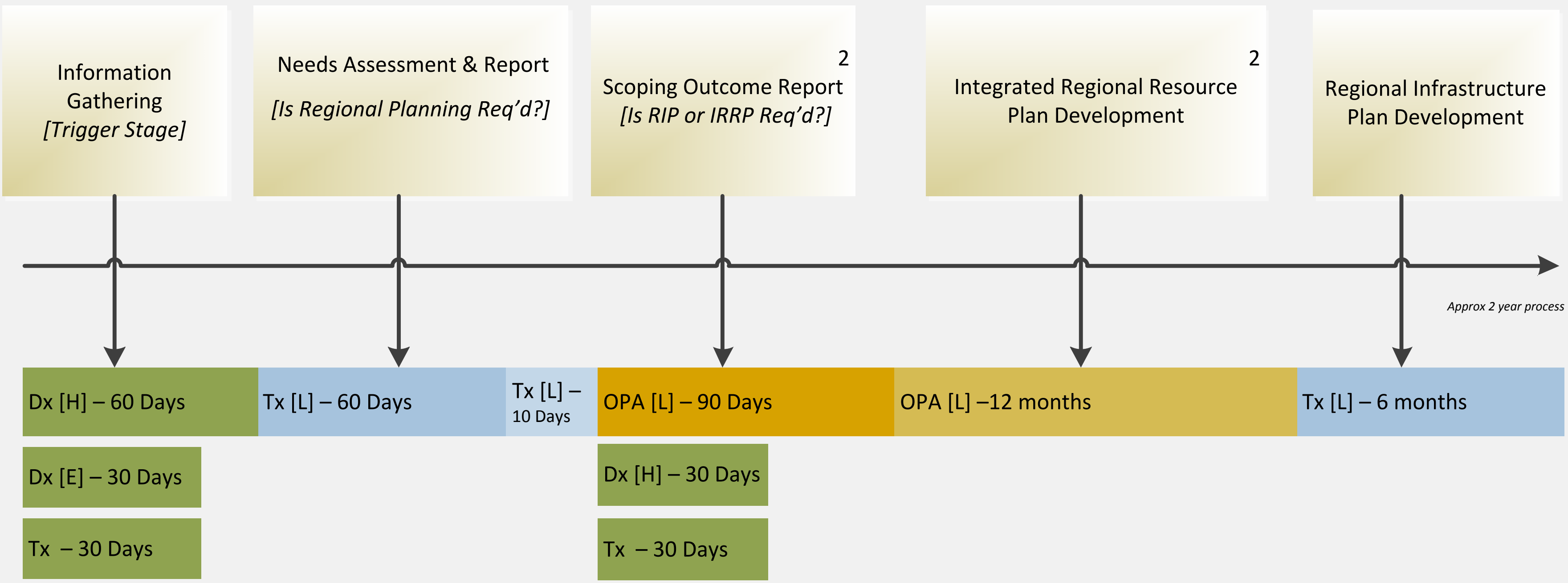
- *See Attachment for Regions – Table & Maps*

Proposed Code Amendments: High Level Overview

- <u>Regional Planning Process</u>
  - Intended to 'support' process in WG Report (i.e., not 'define' process)
  - *Accountabilities* of Transmitters and LDCs
  - *Timelines* for major planning steps & information requirements
  - Identifies *supporting documentation* for applications
- <u>TSC Cost Responsibility Rule Changes</u>
  - Reduce/remove barriers to regional plan execution
  - Capital Contribution "refund" sunset period extended (5 to 15 years)
  - Elimination of "otherwise planned" provision (section 6.3.6)
- <u>Asset Redefinition</u>
  - Reduce/remove barriers to regional plan execution
  - 115/230 kV auto-transformers consistently defined as "Network"
  - Broader "Network" & narrower "Line Connection" definitions
  - Assets only to be redefined on *go forward basis* (as upgraded)

Overview: Timelines in Proposed Code / OPA Licence Amendments

Regional Infrastructure Planning Process [w/ IRRP]



Dx [H] – Host Distributor
Dx [E] – Embedded Distributor
Tx [L] – Lead Transmitter
Tx – Other Transmitter

Notes

Note 1: When RIP is not finalized, a Planning Status Letter is provided to Dx within 30 days of the request.
Note 2: OPA Responsibilities – Scoping Outcome Report / IRRP –reflects proposed licence amendments.
Note 3: Green boxes denote timelines for provision of information

Note: This chart is intended to provide a high level overview to show how the process and timelines in the Proposed Code Amendments fit together. It is not possible to reflect all proposed timelines. This chart should be used as a guide and the official Notice and Proposed Code Amendments should be relied upon.

Proposed Code Amendments: Documentation to support LDC Rate Applications

Documentation requested from Transmitter to support LDC rate applications will vary depending on circumstances

1. *Needs Assessment Report*
   - where LDC involvement not required in RIP and/or IRRP process

2. *Regional Planning Status Letter*
   - where LDC involvement is required in RIP and/or IRRP process but RIP not yet complete at time of application filing

3. *Regional Infrastructure Plan*
   - where LDC involvement is required in RIP and/or IRRP process and RIP completed at time of application filing

Note: PPWG Report includes a summary of the Required Documentation for Application Submissions in Appendix 5 as well as Template Forms [(1) Appendix 6 and (2) Appendix 8]

OEB Proposed Code Amendments: Next Steps

• Posted for stakeholder comment	May 17
• Stakeholder comments received	June 17
• Final code amendments issued	TBD
• *Proposed amendments to OPA Licence*	*June 3*
• *Final amendments to OPA Licence* *(separate regulatory hearing process)*	*TBD*

- Board endorsed regional planning process in PPWG Report (included in Notice with proposed code amendments)

- Notice indicated PPWG to remain in place as *Regional Planning Standing Committee (*after final code amendments issued) to make refinements based on “lessons learned”
    - Expect some changes in membership

Attachment

Table and Maps of 21 Regions

21 Planning Regions: PPWG Report

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	GTA East	Greater Bruce/Huron
GTA North	London area	Niagara
GTA West	Peterborough to Kingston	North of Moosonee
KWCG	South Georgian Bay/Muskoka	North/East of Sudbury
Metro Toronto	Sudbury/Algoma	Renfrew
Northwest Ontario		St. Lawrence
Windsor-Essex		

Note: PPWG Report includes Appendix 4 listing LDCs in each region.

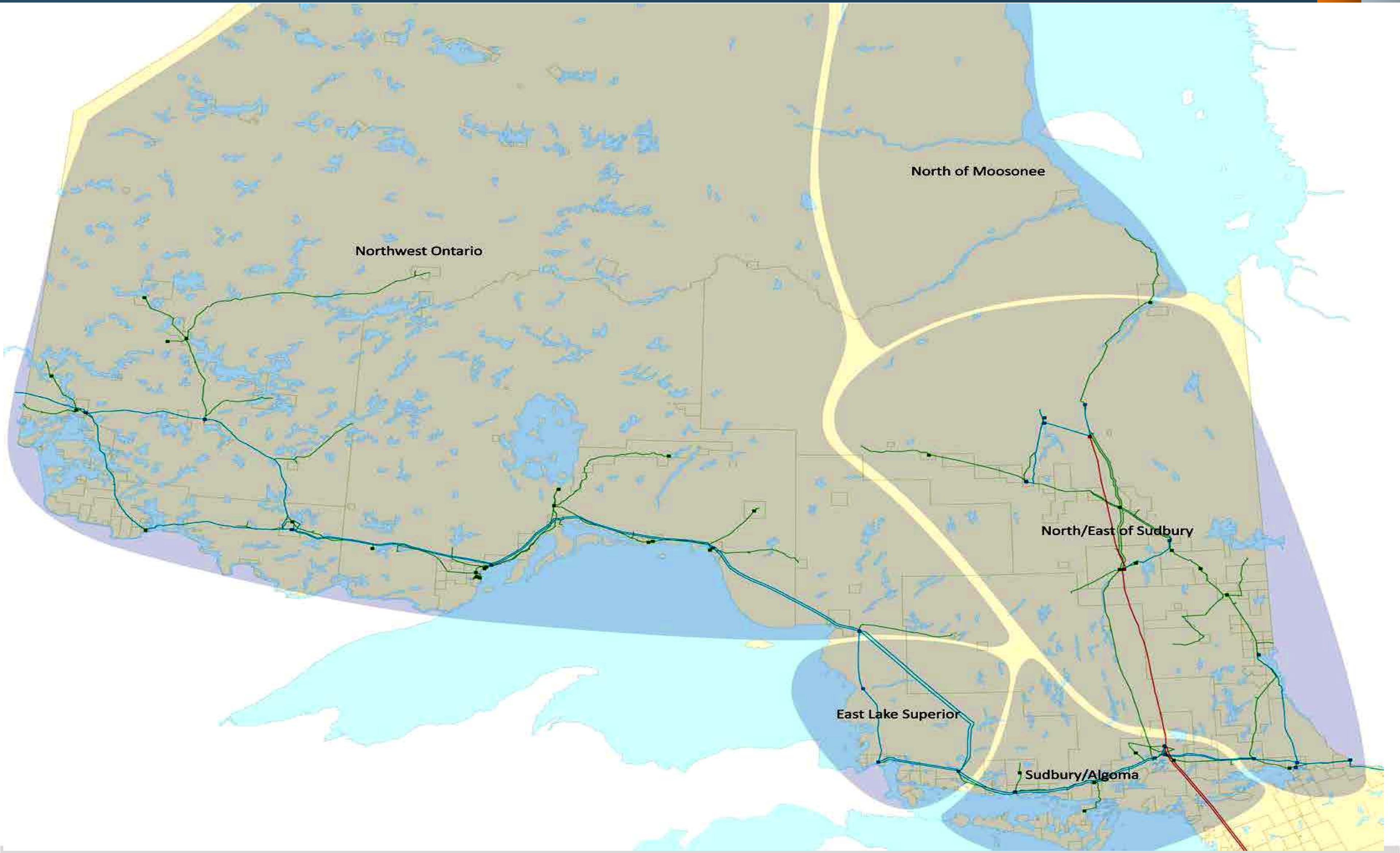
Map 1

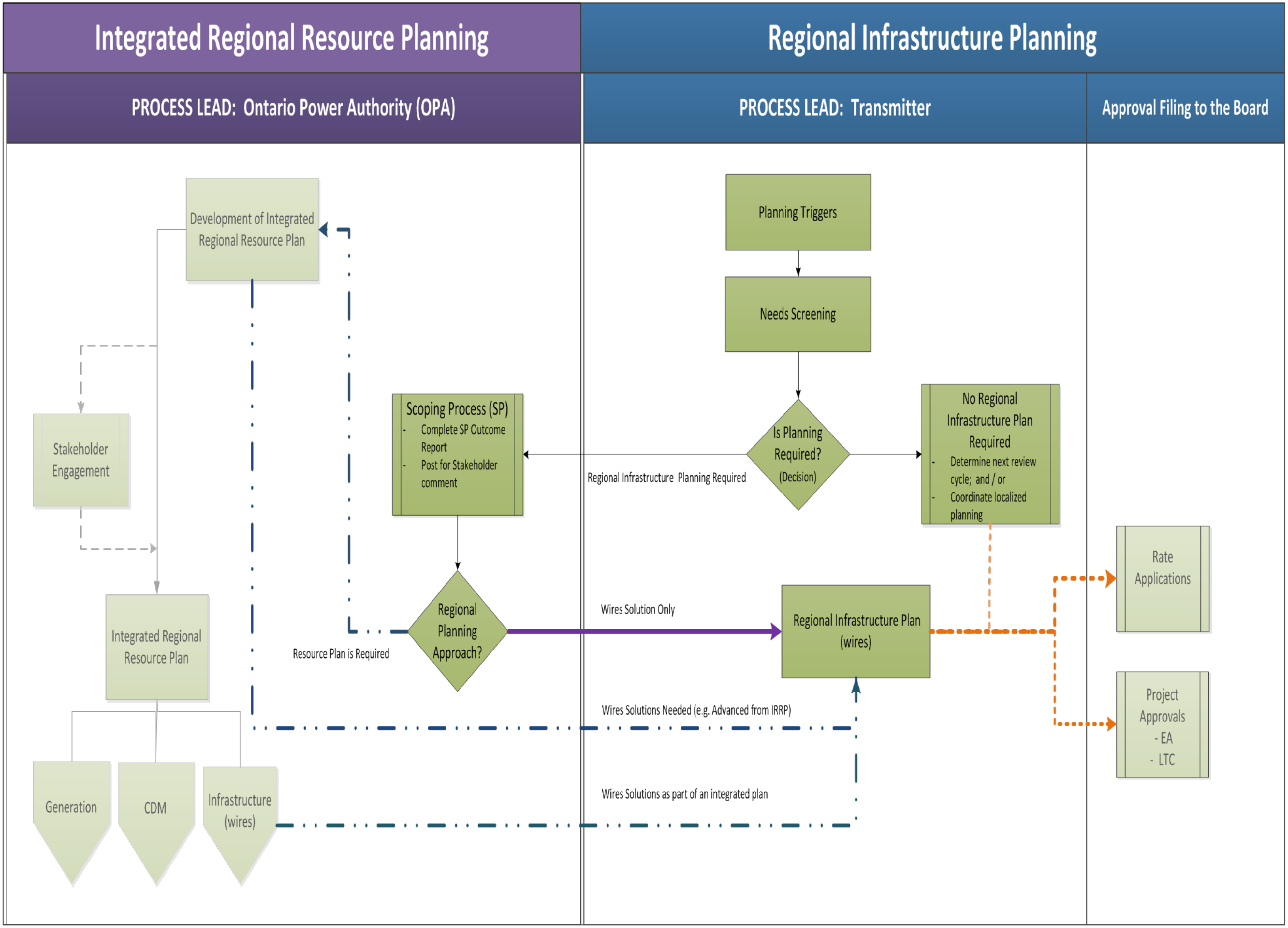
Note: PPWG Report includes maps setting out the regions in Appendix 3 .

Map 2

Renfrew
Greater Ottawa
South Georgian Bay/Muskoka
St. Lawrence
Peterborough to Kingston
Greater Bruce/Huron
KWCG
Niagara
Burlington to Nanticoke
Chatham/Lambton/Sarnia
London area
Windsor/Essex

Map 3


North of Moosonee
Northwest Ontario
North/East of Sudbury
East Lake Superior
Sudbury/Algoma

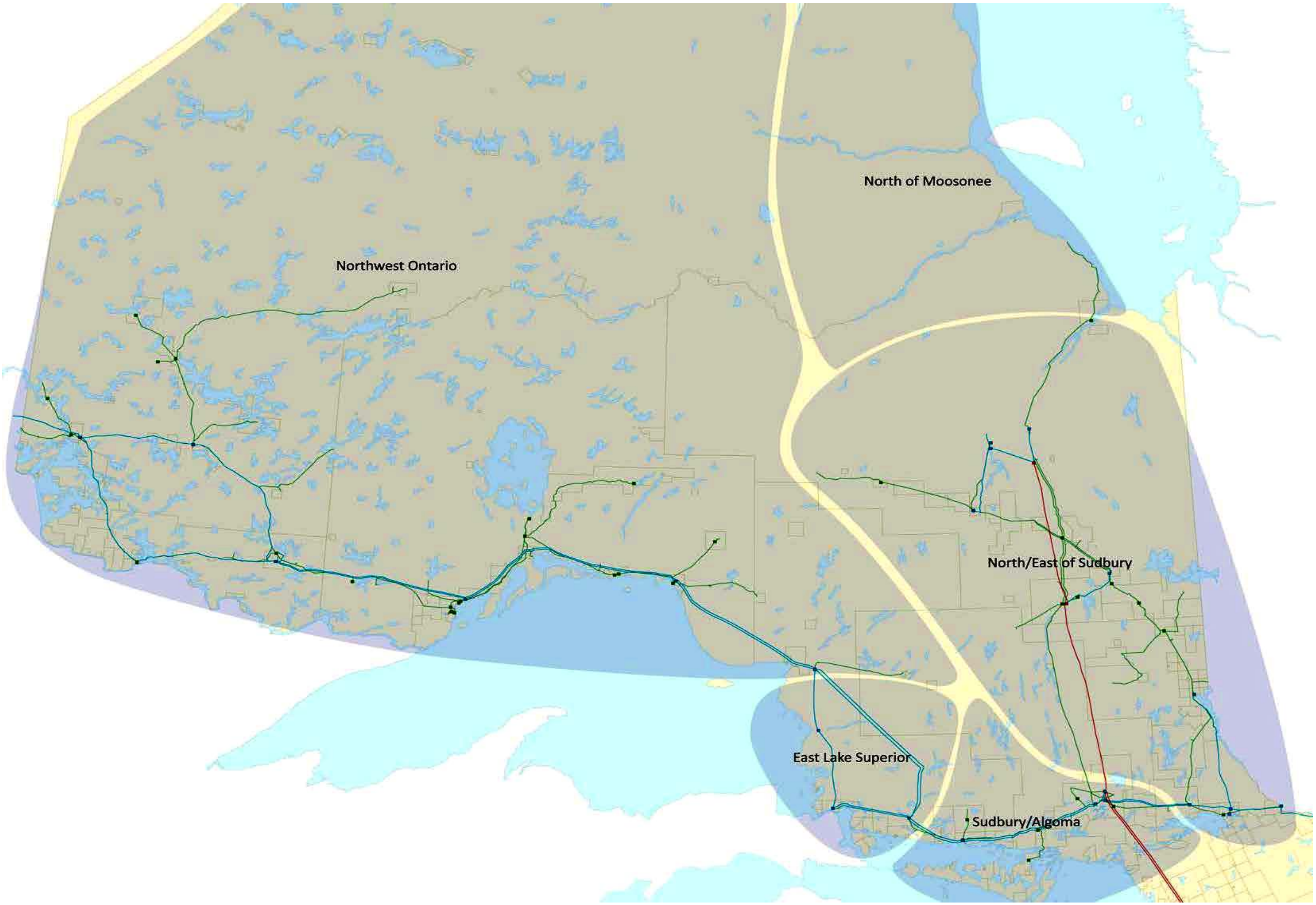


Integrated Regional Resource Planning
Regional Infrastructure Planning
PROCESS LEAD: Ontario Power Authority (OPA)
PROCESS LEAD: Transmitter
Approval Filing to the Board
Development of Integrated Regional Resource Plan
Stakeholder Engagement
Integrated Regional Resource Plan
Generation
CDM
Infrastructure (wires)
Scoping Process (SP)
- Complete SP Outcome Report
- Post for Stakeholder comment
Regional Planning Approach?
Resource Plan is Required
Planning Triggers
Needs Screening
Is Planning Required? (Decision)
Regional Infrastructure Planning Required
No Regional Infrastructure Plan Required
- Determine next review cycle; and / or
- Coordinate localized planning
Wires Solution Only
Regional Infrastructure Plan (wires)
Wires Solutions Needed (e.g. Advanced from IRRP)
Wires Solutions as part of an integrated plan
Rate Applications
Project Approvals
- EA
- LTC

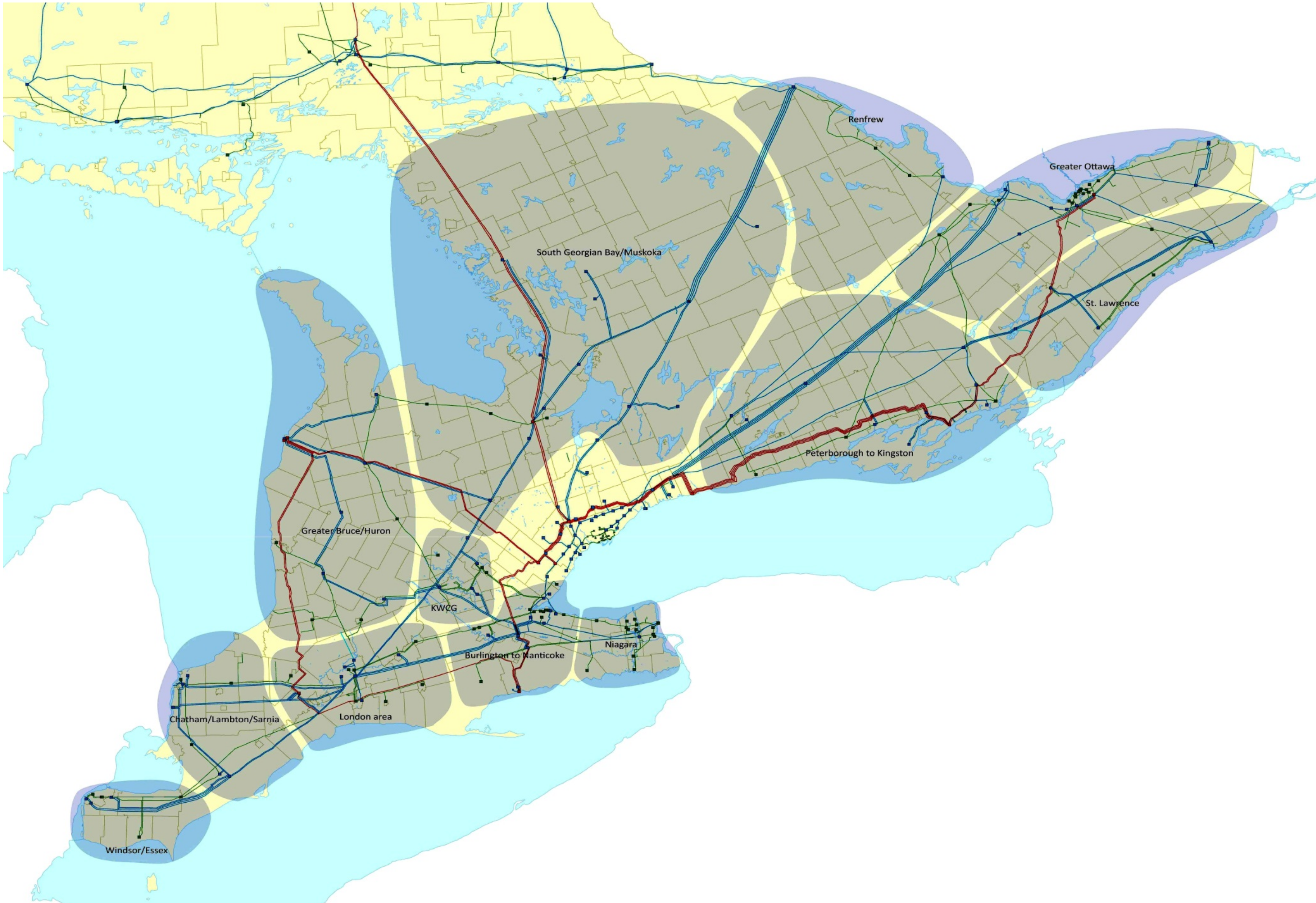
Attachment – Table and Maps of 21 Regions

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	GTA East	Greater Bruce/Huron
GTA North	London area	Niagara
GTA West	Peterborough to Kingston	North of Moosonee
KWCG	South Georgian Bay/Muskoka	North/East of Sudbury
Metro Toronto	Sudbury/Algoma	Renfrew
Northwest Ontario		St. Lawrence
Windsor-Essex		

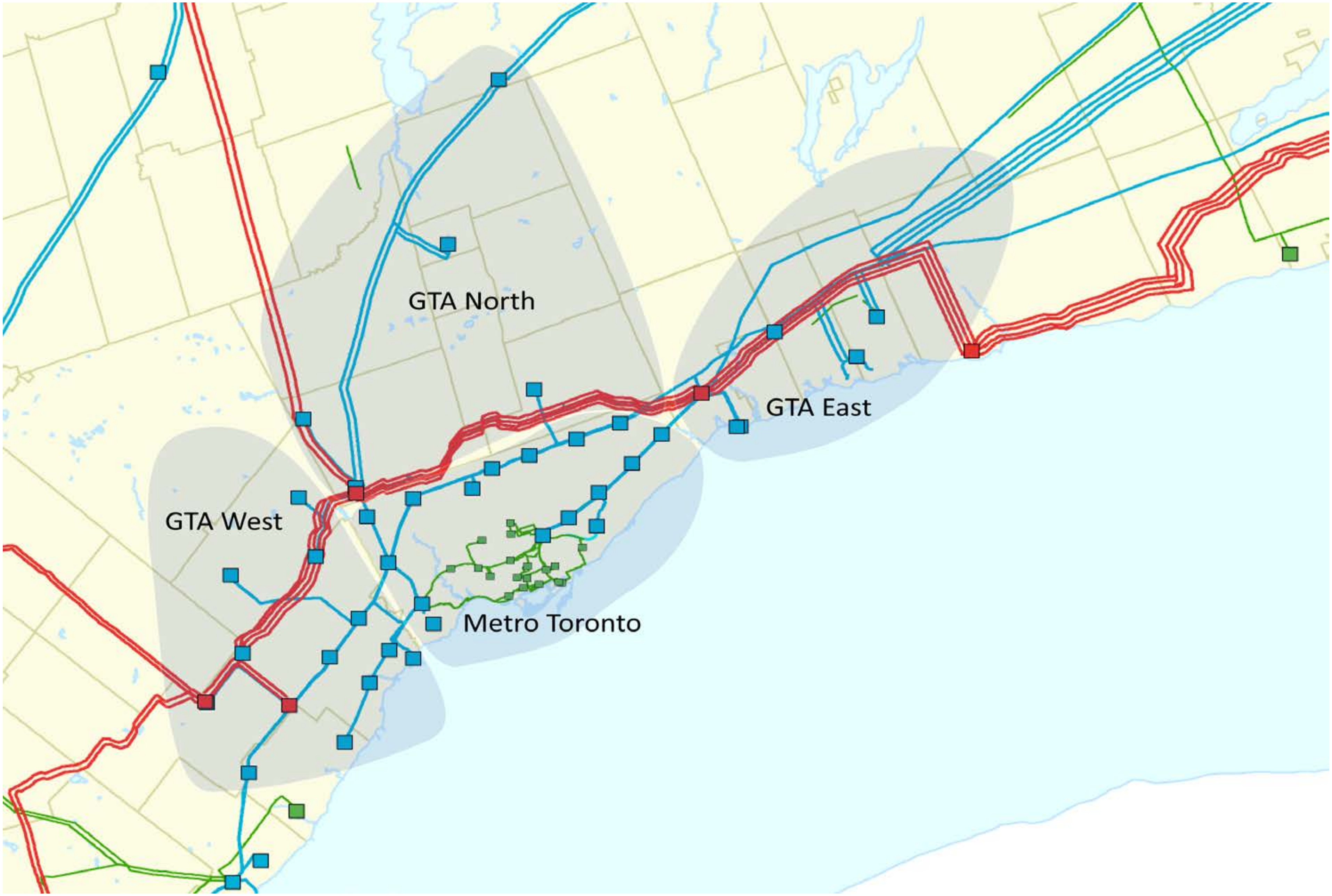
1. Planning Zones – Northern Ontario



2. Planning Zones –Southern Ontario



3. Planning Zones – GTA



Group Priority List - *21 Planning Regions*

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	GTA East	Greater Bruce/Huron
GTA North	London area	Niagara
GTA West	Peterborough to Kingston	North of Moosonee
KWCG	South Georgian Bay/Muskoka	North/East of Sudbury
Metro Toronto	Sudbury/Algoma	Renfrew
Northwest Ontario		St. Lawrence
Windsor-Essex		

Please Reference Appendix 4 for a complete listing

DOCUMENTATION REQUIREMENTS - 2013

Scenario	Regional Group	Documentation	Delivered by
1. ***NO*** Infrastructure Plan Initiated	Group 2 / Group 3	Group Priority List	WG Report
2. ***NO*** Infrastructure Plan Needed	Group 1	Planning Status Letter	Transmitter
3. Infrastructure Plan Needed; but ***Incomplete***	Group 1	Planning Status Letter	Transmitter
4. IRRP Review Needed; ***Incomplete***	Group 1	Planning Status Letter and supporting documents	OPA
5. IRRP Complete – Infrastructure Plan ***Incomplete***	Group 1	Planning Status Letter and copy of the IRRP	Transmitter
6. Infrastructure Plan ***Complete***	Group 1	Regional Infrastructure Plan	Transmitter

Please Note: As this process is in transition and the timing to deliver any products may vary; Distributors are **encouraged** *to contact their Account Manager (OPA or Hydro One) and make a request for the Planning Status Letter as early as possible.*

DOCUMENTATION REQUIREMENTS - 2014

Scenario	Regional Group	Documentation	Delivered By
1. ***NO*** Infrastructure Plan Initiated	Group 2 Group 3	Group Priority List	Hydro One Website
2. ***NO*** Infrastructure Plan Needed	Group 1 Group 2	Needs Assessment Report	Transmitter
3. Infrastructure Plan Needed; but ***Incomplete***	Group 1 Group 2	1. Scoping Outcome Report *(if available)* 2. Planning Status Letter	Transmitter; Requested by the Distributor
4. IRRP Review Needed; ***Incomplete***	Group 1 Group 2	1. Scoping Outcome Report *(if available)* 2. Planning Status Letter	OPA; Requested by the Distributor
5. IRRP Complete – Infrastructure Plan ***Incomplete***	Group 1 Group 2	1. Planning Status Letter 2. IRRP	Transmitter ; Requested by the Distributor
6. Infrastructure Plan ***Complete***	Group 1 Group 2	Regional Infrastructure Plan	Transmitter

NOTE 1: Embedded Distributor is required to requests supporting documentation

NOTE 2: Lead Transmitter is obliged to provide a distributor with a status of any regional plan

Ontario Energy Board
Commission de l’énergie de l’Ontario

2014 Cost of Service Orientation Session

Integrated Planning Requirements – Part 2

Chapter 5: *Consolidated Distribution System Plan* Filing Requirements

July 24, 2013

Stephen Cain
Policy Advisor, Regulatory Policy

this presentation consists of:

- RRFE: objectives, planning policy & expectations for distributor plans
- Chapter 5 relationship to Chapter 2
- filing: who, when & how
- key elements
- highlights by section

Renewed Regulatory Framework: objectives

- shift focus from utility cost to value for customers
- better align utility reliability and quality of service levels with customer expectations
- institutionalize continuous improvement and innovation
- provide for a comprehensive approach to network investments to achieve optimum results
- better align timing and pattern of expenditures with cost recovery
- provide a sustainable, predictable, efficient and effective regulatory framework

Renewed Regulatory Framework: planning policy

- integrated, longer term planning underpins rate setting
- information on asset management and capital expenditure planning policies and practices enables robust regulatory assessment of distributors' applications
- cost effective, timely and efficient regional "wires" investments will result from
  - coordinated planning among affected distributor and transmitter members of a 'region', and
  - the use of clear and consistent transmission asset definitions and cost responsibility rules

Renewed Regulatory Framework: expectations for and evaluation of distributor plans [5.0.3] [5.0.4]

- the Board expects that a distributor's investment plan will
  - optimize investment across all categories of capital expenditure through a longer term, integrated approach
  - reflect regional and smart grid considerations
  - serve present and future customers
  - place a greater focus on delivering value for money
  - align distributor and customer interests
  - support the achievement of public policy objectives

- good planning will ensure that the RRFE *performance outcomes* for distributors are being achieved

Customer Focus
Operational Effectiveness
Public Policy Responsiveness
Financial Performance

Chapter 5 & Chapter 2: the role of Chapter 5

- implements RRFE policy on matters related to distribution network investment planning by providing electricity distributors with guidance on:
  - the types and characteristics of distributor planning information needed to reflect an integrated, longer term planning approach;
  - information on the distributor's approach to asset management and capital expenditure planning that best enables robust regulatory assessment; and
  - the qualitative & quantitative information on the distributor's capital expenditure plan that can be used to support the Board's assessment of proposed material project and activity expenditures

Chapter 5 & Chapter 2: capital expenditure focus

- Chapter 5 consolidates a distributor’s information
  - on system planning, focussing on the asset management and capital expenditure planning processes used to identify, select, prioritize and schedule all types of investment; and
  - on the resulting integrated 5 year plan, detailing the investments for which costs are proposed for recovery
- Chapter 2 focusses on a distributor’s information
  - on the impact of their proposed capital expenditures as explained in Chapter 5 on test year rate base and the revenue requirement

Chapter 5 filings: who & when?

[5.0.2]
[5.1.3]

- licenced, rate regulated electricity distribution utilities in Ontario
  - when filing a cost of service application for rebasing under the 4th Generation IR or a Custom IR rate plans
  - within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding if filing an application under the ‘Annual IR Index’
  - when filing a Leave to Construct, Incremental Capital Module or Z-factor application if required by the Board

Chapter 5 filing: how?

- a Chapter 5 filing should take the form of a stand-alone document (i.e. “Ex 2-T#-S#”)
- organize the information in the document by using the Chapter 5 section headings beginning with section 5.2; e.g.

Filed: YYYY-MM-DD
EB-2013-###
Exhibit 2
Tab #
Schedule #

Distribution System Plan

1 Distribution System Plan Overview

2 Coordinated Planning with 3rd Parties

3 Performance Measurement for Continuous Improvement

4 Asset Management Process Overview

5 Overview of Assets Managed

6 Asset Lifecycle Optimization Policies and Practices

etc.

or…

Chapter 5 filing: how?

- use a table to clearly map the Chapter 5 headings to the headings used in the document; e.g.

Filed: YYYY-MM-DD
EB-2013-###
Exhibit 2
Tab #
Schedule #

Distribution System Plan

The table below maps the headings used in this document to the section headings used in Chapter 5.

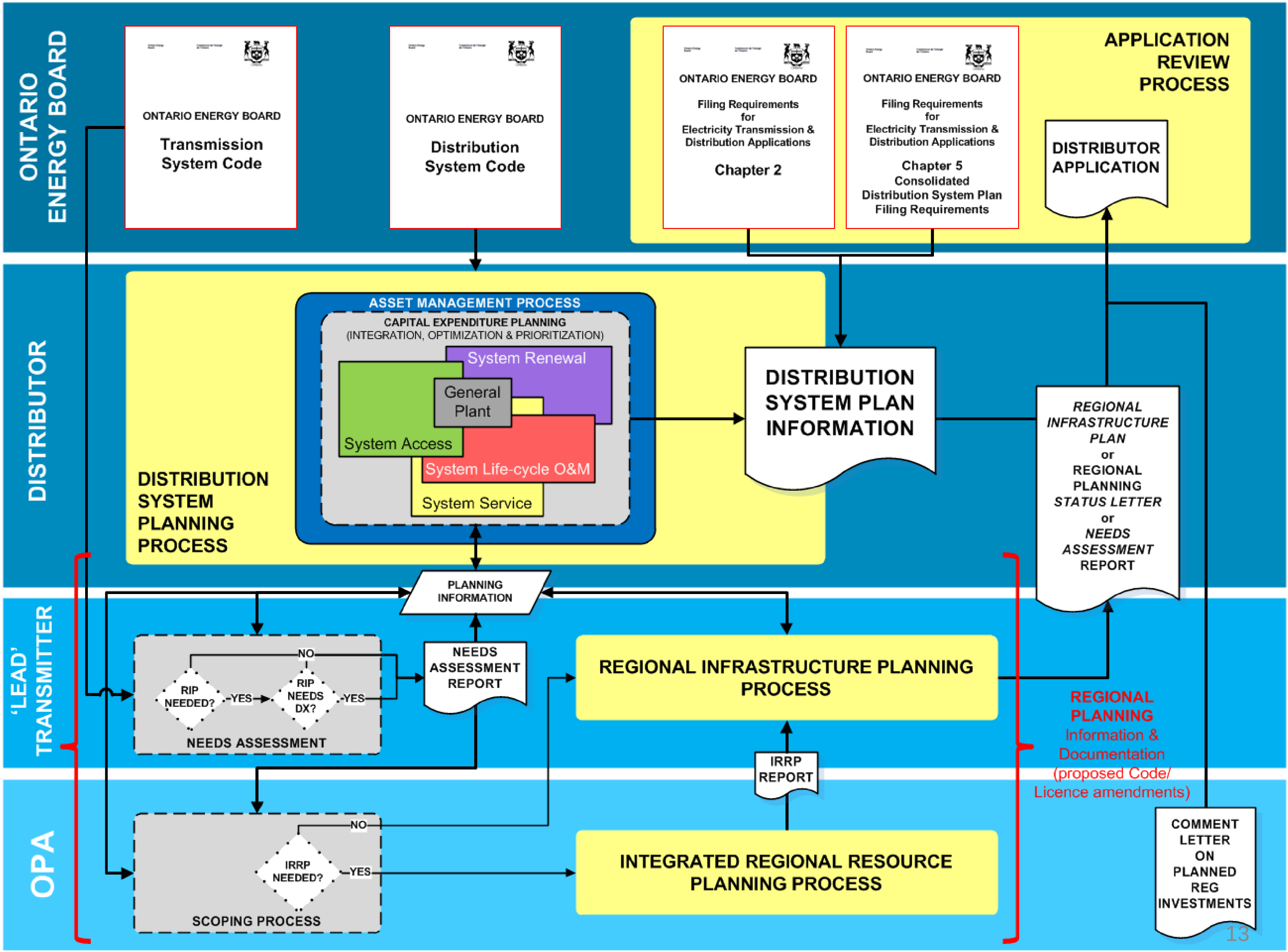
Chapter 5 headings		Current Document	
5.2.1	Distribution System Plan Overview	6	Title F
5.2.2	Coordinated Planning with 3rd Parties	5	Title E
5.2.3	Performance Measurement for Continuous Improvement	4	Title D
5.2.4	Asset Management Process Overview	1	Title A
5.2.5	Overview of Assets Managed	3	Title C
5.2.6	Asset Lifecycle Optimization Policies and Practices	2	Title B

etc.

key elements: regional planning documentation [5.1.4.1]

- <u>proposed</u> DSC amendments set out distributor obligations to participate in regional planning processes, including
  - integrated regional resource planning (IRRP) lead by OPA
  - regional infrastructure planning (RIP) lead by transmitter
- a distributor would obtain from the transmitter and file
  - the most recent ***Needs Assessment*** report if the distributor was not required to participate in the latest RIP process for their region; or
  - if they did participate in the latest RIP process, the ***Regional Infrastructure Plan*** prepared as a result; or
  - an RIP process ***status letter*** if a completed *Regional Infrastructure Plan* was not available at the time of filing

- investments to accommodate renewable energy generation are included in the distributor's capital expenditure plan
  - replaces stand-alone 'GEA Plans'
  - OPA ***comment letter*** on distributor's planned REG investments required
  - material REG investment projects/activities assessed in same way as any other proposed investment
  - costs of "eligible investments" recoverable through provincial cost recovery (incl. 'Direct Benefits' calculations) are included in Chapter 2 filing


ONTARIO ENERGY BOARD
ONTARIO ENERGY BOARD
Transmission System Code
ONTARIO ENERGY BOARD
Distribution System Code
ONTARIO ENERGY BOARD
Filing Requirements for Electricity Transmission & Distribution Applications
Chapter 2
ONTARIO ENERGY BOARD
Filing Requirements for Electricity Transmission & Distribution Applications
Chapter 5 Consolidated Distribution System Plan Filing Requirements
APPLICATION REVIEW PROCESS
DISTRIBUTOR APPLICATION
DISTRIBUTOR
ASSET MANAGEMENT PROCESS
CAPITAL EXPENDITURE PLANNING
(INTEGRATION, OPTIMIZATION & PRIORITIZATION)
System Renewal
General Plant
System Access
System Life-cycle O&M
System Service
DISTRIBUTION SYSTEM PLANNING PROCESS
DISTRIBUTION SYSTEM PLAN INFORMATION
REGIONAL INFRASTRUCTURE PLAN or REGIONAL PLANNING STATUS LETTER or NEEDS ASSESSMENT REPORT
'LEAD' TRANSMITTER
PLANNING INFORMATION
RIP NEEDED?
YES
NO
RIP NEEDS DX?
YES
NEEDS ASSESSMENT
NEEDS ASSESSMENT REPORT
REGIONAL INFRASTRUCTURE PLANNING PROCESS
REGIONAL PLANNING
Information & Documentation (proposed Code/ Licence amendments)
IRRP REPORT
OPA
NO
IRRP NEEDED?
YES
SCOPING PROCESS
INTEGRATED REGIONAL RESOURCE PLANNING PROCESS
COMMENT LETTER ON PLANNED REG INVESTMENTS
13

key elements: smart grid

[5.0.3.4]
[5.4.5.2 B]

- in its *Supplemental Report* on smart grid the Board determined that smart grid is
  - the modernization of the grid
  - integral to distribution system plans
  - a focus of grid-enhancing innovation; and
  - implemented on a regionally coordinated basis
- material grid modernization projects/activities will be assessed using the criteria applicable to any proposed investment (i.e. efficiency, customer value, reliability, safety); other criteria may be used (e.g. cyber-security) where applicable

highlights: Distribution System Plan overview [5.2]

- to set the context and summarize the key elements of the DS Plan:
  - a high level overview and ‘highlights’ of the plan (e.g. objectives; key drivers; priorities; significant or ‘one off’ investments; etc.) [5.2.1]
  - a description of coordinated regional planning activities and impact on current plan [5.2.2]
  - an explanation of the measures and methods the applicant uses to assess ongoing performance against objectives [5.2.3]

highlights: performance reporting & measurement

[5.1.5]
[5.2.3]

- file information on the metrics you use to monitor and assess the effectiveness of your planning process; i.e.
  - measures of how well plan objectives are being met
  - should relate to your objectives; e.g.
    - customer oriented performance
    - cost efficiency and effectiveness
    - asset/system operational performance
- summarize ‘trend’ information (table or graph)

highlights: asset management process [5.3]

- information focusses on the process used to manage system asset maintenance and replacement activities over the lifecycle of the assets, including:
  - an overview of the AM process used [5.3.1]
  - a high level summary of distribution assets in use [5.3.2]
  - an explanation of how ‘replace vs. refurbish’ decisions are made (= ‘asset lifecycle optimization’ policies/practices) [5.3.3]

highlights: capital expenditure plan [5.4]

- information describing the plan at a high level and identifying and explaining the rationale for significant capital expenditures for which cost recovery is sought:
  - a summary of key plan information (e.g. significant projects, their respective main drivers and costs) [5.4.1]
  - a brief explanation of the **process** the applicant uses to plan investments (referencing their asset management process where applicable) [5.4.2]
  - information on the **capability** of a distributor's distribution system to accommodate renewable energy generation; [5.4.3] and
  - a 'capital expenditure summary' (Table 2) to organize previous and prospective capital expenditure information in a **common framework** using high level categories defined by investment drivers [5.4.4]

highlights: Table 2 – capital expenditure summary [5.4.4]

CATEGORY	Historical (previous plan[1] & actual)															Forecast (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access																				
System Renewal																				
System Service																				
General Plant																				
Total																				
System O&M																				

1 2 2 3

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in year 'Test-1' (normally a 'bridge' year): ☐

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

1

aggregated expenditure by category

2

amounts for each category from previous plan for each year

3

blank (no previous plan) for initial Chapter 5 filing

highlights: justifying capital expenditures [5.4.5]

- the information that will be used to assess whether the plan meets the Board's expectations includes:
  - for the plan as a whole, trends in the relationship between investment drivers and expenditures [5.4.5.1]
  - for significant investments more in-depth information in proportion to the 'materiality' of the expenditure is required, including [5.4.5.2]
    - key characteristics of the investment [A]
    - information about the investment that addresses the applicable evaluation criteria the Board will use to assess the expenditure in terms of achieving the four RRFE performance outcomes [B]
    - provide category-specific information that could support the Board's assessment [C]

click to add title

FAQ

Q: Chapter 5 mentions REG investments, but where are ‘Direct Benefits’ calculations filed?

A: Chapter 2 (as revised) includes guidance and tables for this purpose

Q: I have a documented *Asset Management Plan*; can section 5.3.1 – 5.3.3 be addressed by including it as an Appendix to my DSP Exhibit?

A: Provide a clear indication in the Exhibit as to where the information for each section can be found

Q: Does Table 2 require project-by-project data?

A: Aggregated data by category is required

Q: Note 1 to Table 2 notwithstanding, can ‘plan’ data for the historical period (e.g. ‘total’ capex; system O&M) be included in my initial Chapter 5 filing?

A: Any information that supports your application can be included as appropriate

Q: For the purposes of the ‘Explanatory Notes’ on Table 2, what is a ‘marked’ variance?

A: Some variance is expected; a ‘marked’ variance is one that ‘stands out’ relative to the others in the series

Q: What’s the best way to organize information for sections 5.4.5.2 A, B and C (for material projects/activities)?

A: Applicants should consider consolidating all the information pertinent to each material project/activity to promote clarity and better understanding of the expenditure

Thank you

Need information?

Market Operations Hotline: 416-440-7604

Email: market.operations@ontarioenergyboard.ca

Ontario Energy Board *Commission de l’énergie de l’Ontario*

Ontario

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications

Chapter 5

Consolidated Distribution System Plan

March 28, 2013

Table of Contents

CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

Glossary

Where applicable, definitions set out in the Distribution System Code (DSC) apply to terms used in these filing requirements. Certain other terms used here are explained below.

Distribution System Plan duration is the duration of a distributor's *Distribution System Plan*, which is a minimum of ten (10) years in total and comprised of an *historical period* and a *forecast period*

Forecast period is the last five (5) years of the *Distribution System Plan duration*, consisting of five (5) forecast years, beginning with the Test year

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Historical period is the first five (5) years of the *Distribution System Plan duration*, consisting of five (5) historical years, ending with the Bridge year

REG investments accommodate the connection of renewable energy generation (including connection assets, expansions and/or renewable enabling improvements) the costs of which are the responsibility of the distributor as set out in the DSC. REG investments can be stand-alone or integrated into a project/activity; and are to be categorized for the purposes of section 5.4 in the same way as any other investment

Regional Infrastructure Plan is a document issued by the transmitter leading a Regional Planning Process that identifies forecast regional electricity service requirements, and describes and justifies the optimal infrastructure investments planned to meet those requirements

Regional Planning Process is a consultation involving distributors, transmitter(s), and the Ontario Power Authority convened for the purpose of exchanging information related to system planning, coordinating the modification of a regional electricity transmission system, and preparing and issuing a Regional Infrastructure Plan

System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

System O&M are routine operations and maintenance activities carried out to sustain required distribution system performance to the end of the subject asset's service life

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

5.0 Introduction

These filing requirements set out the information required by the Board under the renewed regulatory framework for electricity to assess distributor applications involving planned expenditures on distribution system and other infrastructure.[1] For the purposes of these filing requirements, a *Distribution System Plan* ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan, where:

- an *Asset Management Process* is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus; and
- a *Capital Expenditure Plan* sets out and robustly justifies according to the Board's standard requirements for evaluation a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance expenditures.

Filing DS Plans consistent with these requirements will ensure that the Board's expectations for a distributor's planning are met; namely, that the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives.[2]

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity[3], and necessary to ensure that the performance outcomes the Board has established for electricity distributors are being achieved:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

[1] The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. See *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*; (the "*RRFE Report*"); p. 2.

[2] *RRFE Report*; p. 1.

[4] *RRFE Report*; p. 36.

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

DS Plan filings must enable the Board to assess whether and how a distributor has planned to deliver value to customers. One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in a manner that considers rate impacts. To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments.[4]

5.0.1 Purpose of filing a Distribution System Plan

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity. Filing a DS Plan with an application to the Board will provide information to the Board and interested stakeholders including but not necessarily limited to a distributor's:

- asset related performance objectives and approach to evaluating its performance relative to those objectives;
- approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and
- plan for capital-related expenditures over the five-year forecast period.

5.0.2 Application and scope

These filing requirements apply to licenced, rate regulated electricity distribution utilities in Ontario when filing DS Plans as required by the Board as set out in section 5.1.3 of these requirements.

5.0.3 Framework for distribution system plans

The content of these filing requirements has been informed by the Board's expectations for distribution system planning under the renewed regulatory framework for electricity.

[4] *RRFE Report*; p. 36.

5.0.3.1 Integrated planning

An integrated approach to planning, whereby investments for system renewal and expansion, renewable generation connections, smart grid development and implementation, and regionally planned infrastructure are planned and optimized together, will provide the necessary foundation for distribution rate-setting under the renewed regulatory framework; help distributors to pace and prioritize projects; and support the achievement of the four outcomes for electricity distributors.[5]

5.0.3.2 Longer term planning horizon

Under the renewed regulatory framework, a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles, which are a minimum of five-years in expected duration.[6] This longer term approach should:

- enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and distributors;
- facilitate the cost-effective and efficient implementation of distributor DS Plans and thereby the achievement of customer service and cost performance outcomes; and
- help distributors to manage consumer rate impacts.[7]

5.0.3.3 Regional considerations

Planning the distribution system infrastructure in a regional context will help promote the cost effective development of electricity infrastructure in Ontario. Regional issues and requirements are to be considered in individual distributor system planning processes.[8] Accordingly, these filing requirements provide that where applicable, a distributor file information on the Regional Planning Process(s) in which it was a participant; on the Regional Infrastructure Plan provided by the transmitter; and information demonstrating that the Regional Infrastructure Plan has been appropriately considered and addressed in the development of the distributor's DS Plan.

5.0.3.4 Smart grid development and implementation

Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and

[5] *RRFE Report*; p. 31.
[6] *RRFE Report*; p. 31.
[7] *RRFE Report*; p. 10.
[8] *RRFE Report*; p. 39.

scale.[9] These filing requirements therefore include DS Plan information regarding, where appropriate:

- the activities a distributor has undertaken in order to understand their customers' preferences (e.g., data access and visibility, participating in distributed generation, and load management) and how they have addressed those preferences;
- the options a distributor has considered for facilitating customer access to consumption data in an electronic format;
- the mechanisms that facilitate "real-time" data access and "behind the meter" services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs;
- the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability);
- the technology-enabling opportunities a distributor has considered regarding operational efficiencies and improved asset management; and
- the distributor's awareness and adoption of innovative processes, services, business models, and technologies.[10]

5.0.4 The Board's evaluation of DS Plans

DS Plan filings must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes the Board has established for electricity distributors as explained below. Section 5.4.5 explains the specific criteria the Board will use to evaluate whether a DS Plan and in particular the material[11] projects/activities proposed for cost recovery in a DS Plan address these four outcomes.[12]

Customer Focus

A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences. As indicated in the provisions that follow, this is accomplished by providing information on customer engagement to identify preferences; the value proposition the DS Plan represents for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers and participants in a Regional Planning Process that were considered in the course of planning investment projects and activities.

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9 See *Report of the Board - Supplemental Report on Smart Grid* (EB 2011-0004); February 11, 2013 (the "*Smart Grid Report*"); pp. 4 – 5.

10 *Smart Grid Report*; pp. 9 – 16.

11 A project or activity is "material" if the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* is met.

12 For details on the evaluation criteria and how the Board will use them to evaluate investments, see the *Smart Grid Report*; pp. 17 – 21.

Operational Effectiveness

DS Plans must show that a distributor's asset management and capital expenditure planning processes are designed to identify and take advantage of opportunities for continuous improvements in productivity and cost performance, while delivering on a distributor's explicitly stated system reliability and quality objectives.

Public Policy Responsiveness

A distributor's DS Plan must explain how the expenditure planning process has been integrated and rationalized so as to permit timely and appropriate expenditures in relation to a distributor's government-mandated obligations (e.g., in legislation or regulatory requirements imposed further to Ministerial directives to the Board).

Financial Performance

DS Plans must show that a distributor's financial viability and operational effectiveness will endure over the long term including by sustaining efficiencies gained through prudent capital-related expenditure planning and DS Plan execution.

5.0.5 Form of these filing requirements

To implement the policy objectives of the renewed regulatory framework, filing requirements related to Distribution System Plans, including information on planned investments related to investments to accommodate the connection of renewable energy generation (REG) and/or smart grid development activities and expenditures (see sections 5.1.2 and 5.0.3.4 respectively), have been consolidated in this Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications* (*CoS FRs*) Accordingly, these filing requirements replace the Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*.

5.1 General & Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application.[13] As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and

[13] *RRFE Report*; p. 35.

clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.[14]

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

Table 1 – Investment Categories & Example Drivers and Projects/Activities

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
system access	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
system access	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
system service	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Note: 1. Includes only 19## series accounts.

[14] For the Board's conclusions in relation to consolidating and harmonizing its planning-related filing requirements see *RRFE Report*; p. 31.

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system
- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.
- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements
- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

5.1.2 Investments related to renewable energy generation

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *OEB Act*.

5.1.3 Time of filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

5.1.4 Planning in consultation with third parties

5.1.4.1 Regional planning and consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:
   - forecast load at existing (and proposed, if any) points of interconnection;
   - forecast renewable generation connections and any planned network investments to accommodate the connections;
   - investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and
   - the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.

2. Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.

5.1.4.2 Renewable energy generation investments

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor's filing timetable.

2. The Board expects that the OPA comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

5.1.5 Performance reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

5.2.1 Distribution System Plan overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to

a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

c) the period covered by the DS Plan (historical and forecast years);

d) an indication of the vintage of the information on investment ‘drivers’ used to justify investments identified in the application (i.e. the information should be considered “current” as of what date?);

e) where applicable, an indication of important changes to the distributor’s asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing; and

f) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

5.2.2 Coordinated planning with third parties

To demonstrate that a distributor has met the Board’s expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) a description of the consultation(s), including

- the purpose of the consultation (e.g. Regional Planning Process);
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process (e.g. customers; transmitter; OPA);
- the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and
- an indication of whether the consultation(s) have or are expected to affect the distributor’s DS Plan as filed and if so, a brief explanation as to how.

b) where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:

- the role of the distributor in the consultation;
- the status of the consultation process; and

- where applicable the expected date(s) on which final deliverables are expected to be issued.

c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.3 Performance measurement for continuous improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:
    - customer oriented performance (e.g. consumer bill impacts; reliability; power quality);
    - cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and
    - asset and/or system operations performance.

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

    Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

c) explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

[15] The data should be calculated as stipulated in section 2.1.4.2 of the Board's Reporting and Record Keeping Requirements.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset management process overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

a) a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

b) information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- asset register
- asset condition assessment
- asset capacity utilization/constraint assessment
- historical period data on customer interruptions caused by equipment failure
- reliability-based 'worst performing feeder' information and analysis
- reliability risk/consequence of failure analyses.

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.2 Overview of assets managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

a) a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;

b) a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

c) information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled; and

d) an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

   - where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

5.3.3 Asset lifecycle optimization policies and practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:

a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

   - a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;
   - a description of maintenance planning criteria and assumptions; and

- a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).

b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor’s capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);
- to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and
- to study or demonstrate innovative processes, services, business models, or technologies.

5.4.2 Capital expenditure planning process overview

The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor’s capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor’s policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor’s asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.3 System capability assessment for renewable energy generation

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and

e) constraints for an embedded distributor that may result from the connections.

5.4.4 Capital expenditure summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or 'trigger') driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor's actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that 'Plan' expenditures over the historical period refer to a distributor's previous plan for capital expenditures *after* adjustments (if any) occasioned by the Board's decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to 'actual' spending over the historical period. For example, a large expenditure over a relatively short period for a 'one-off' project (e.g. a distribution station) can cause a temporary 'step change' in category C spending compared to the trend in actual expenditures over the historical period.

While year over year 'Plan vs. Actual' variances for individual investment categories are expected, explanatory notes should be provided where

- for any given year "Total" 'Plan' vs. 'Actual' variances over the historical period are markedly positive or negative; or
- a trend for variances in a given investment category is markedly positive or negative over the historical period.

Table 2 – Capital Expenditure Summary

CATEGORY	Historical (previous plan[1] & actual)															Forecast (planned)				
	Test-5			Test-4			Test-3			Test-2			Test-1[2]			Test	Test+1	Test+2	Test+3	Test+4
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access																				
System Renewal																				
System Service																				
General Plant																				
Total																				
System O&M																				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in year 'Test-1' (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

5.4.5 Justifying capital expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- comparative expenditures by category over the historical period;
- the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;
- the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);
- information related to the distributor's system capability assessment (see section 5.4.3)

5.4.5.2 Material investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications*. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
- related customer attachments and load, as applicable
- start date, in-service date and expenditure timing over the planning horizon
- the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
- if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available
- information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities
- where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular)

B. Evaluation criteria and information requirements for each project/activity

The Board's evaluation of material investments aligns with the outcomes set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. *Efficiency, Customer Value, Reliability*
    a) identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment
    b) indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c)

c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

- explain the effect of the investment on system operation efficiency and cost-effectiveness
- the net benefits accruing to customers as a result of the investment
- the impact of the investment on reliability performance including on the frequency and duration of outages

Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. *Safety*

Provide information on the effect of the investment on health and safety protections and performance

3. *Cyber-security, Privacy*

Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. *Co-ordination, Interoperability*

a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. *Economic Development*

Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. *Environmental Benefits*:

Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. Category-specific requirements for each project/activity

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) *System access* – projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

   In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

   Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:

   - factors affecting the timing/priority of implementing the project
   - factors relating to customer preferences or input from customers and other third parties
   - factors affecting the final cost of the project
   - how controllable costs have been minimized
   - whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why
   - whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not
   - where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:
     – the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
     – the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
       i. a project configured solely to meet the obligation; and

   ii. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.

- where applicable, the results of the ‘final economic evaluation’ carried out as per section 3.2 of the DSC
- where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered

b) *System renewal* – projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor’s discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor’s justification of each sustainment project/activity, including (where applicable) but not restricted to:

- a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to
  - the distributor’s asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)
  - information on the condition of the assets relative to their typical life-cycle; and performance record of the assets targeted by the project
  - the number of customers in each customer class potentially affected by a failure of the assets included in the project
  - quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
  - qualitative customer impacts (e.g. customer satisfaction; customer migration) with associated risk level(s)

  - the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)

- other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)
- identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project
- identification of reliability and or safety factors that may have played a role
- where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.
- where the proposed project meets the requirement for 'like for like' renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

c) *System service* – projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:

- where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable

- where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs
- description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.
- identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system
- identifying and explaining the factors affecting implementation timing/priority
- providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.

  Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.

d) *General plant* – projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

   Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:

- the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;
- For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Treatment of REG Investments

Birgit Armstrong, Advisor, Electricity Rates
July 24, 2013

Legal foundation

- The *Green Energy and Green Economy Act, 2009* amended the *Ontario Energy Board Act, 1998* to introduce a mechanism under section 79.1
    - **79.1** (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules. 2009, c. 12, Sched. D, s. 14.

O. Reg. 330/09 - Rate Protection Formula

- Ontario Regulation 330/09 calculation of rate protection:

A = B – C

  - **A** = the amount of **rate protection** to be provided to prescribed consumers of classes of consumers in a distributor's service area
  - **B** = the **eligible investment cost** determined by the Board to be the responsibility of the distributor in accordance with the DSC , and
  - **C** = the amount the Board determines to represent the **direct benefits** that accrue to prescribed consumers or classes of consumers as a result of all or part of the eligible investment made or planned to be made by the distributor

Role of the IESO – O.Reg 330/09

- In accordance with Reg. 330/09, the Board determines the appropriate rate protection amounts, in aggregate and on a monthly basis, for each qualifying distributor that has made an "eligible" renewable energy generation connection investment

- The Board then issues a Decision and Order that sets out the following:

  - The aggregate and monthly rate protection amount to be collected by the Independent Electricity Systems Operator ("IESO") from all market participants

  - The monthly compensation payments the IESO is to make to each qualifying distributor identified in the Board Order based on the rate protection amounts determined by the Board

Rate Protection in 2013

- Total amount collected by the IESO in 2013 (EB-2013-0231, issued July 1, 2013) is $20,135,637

- The IESO monthly compensation payments to distributors are as follows:

Hydro One Networks Inc.	$1,641,667
Hydro One Brampton Networks Inc.	$ 13,810
Enersource Hydro Mississauga Inc.	$ 5,356
Horizon Utilities Corporation	$ 707
Guelph Hydro Electric Systems Inc.	$ 2,213
Powerstream Inc.	$ 27,114
Thunder Bay Hydro Distribution Inc.	$ 1,321

DSP vs. Chapter 5: What changed, what stayed the same

- Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (“DSP”), revised May 17, 2012 have been superseded by Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications, issued March 28, 2013

DSP vs. Chapter 5: What changed, what stayed the same

- **What changed?**
  - A distributor is no longer required to file a stand-alone Green Energy Act (GEA) Plan (Basic or Detailed)
  - A distributor is required to file a Distribution System (DS) Plan, which includes renewable energy generation (REG) investments

DSP vs. Chapter 5: What changed, what stayed the same

- **What stayed the same?**
  - DSC Amendments, October 21, 2009, which assigned cost responsibilities between distributor and generator in relation to the connection of renewable generation facilities (EB-2009-0077) remain unchanged
  - Three categories - Connection assets; Expansions; Renewable enabling improvements (REI):
    - For connection assets, the generator bears 100% of the cost;
    - For expansions: (i) if the expansion is identified in a Board-approved plan or is otherwise approved or mandated by the Board, the distributor is responsible for 100% of the costs; and (ii) in all other cases, the distributor is responsible for the costs up to the "renewable expansion cost cap" ($90,000 per MW of capacity of the connecting generator) and any amount above that cap is the responsibility of the generator; and
    - For REIs, the distributor bears 100% of the cost.

DSP vs. Chapter 5: What changed, what stayed the same

- **What stayed the same?**
  - Distributor is still required to provide the capacity of their distribution system to accommodate REG, including:
    - A summary of load and REG connection forecast by feeder/substation,
    - Information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or REG capacity
  - Prior to filing a DS Plan a distributor must submit relevant REG information to the OPA and request that the OPA provide a letter commenting on the information, which is part of the DS Plan filing

DSP vs. Chapter 5: What changed, what stayed the same

- **Funding mechanism**:
  - "Old" DSP:
    - Funding Adder for Direct Benefits and Provincial Rate Protection (IESO)
    - 3 Renewable Generation Connection DVAs
    - 3 Smart Grid DVAs
    - Prudence review at next rebasing application
  - Once a "new" DSP is filed under Chapter 5:
    - No new DVAs
    - Discontinuation of existing DVAs
    - Disposition of existing balances
    - Variance accounts for 'eligible investments' under O.Reg. 330/09
    - Direct Benefit in Rate Base, Provincial Rate Protection (IESO)

Direct Benefits – What changed, what stayed the same?

- **Chapter 5 Funding Mechanism – Direct Benefits:**
  - A Chapter 5 filing should include single/multi-year REG investments (as applicable), including the Direct Benefit portion for Board approval:
    - Renewable Enabling Improvements (REI) 6%
    - Expansions 17%
    - Or file a study
  - Multi-year approval process for REG investment remains the same as under the old DSP
  - During IRM period following a Chapter 5 filing:
    - Direct benefit amount will be part of rate base, not a rate adder and therefore will not change through the IRM term

Provincial Rate Protection – What changed, what stayed the same?

- **Chapter 5 Funding Mechanism – Provincial Rate Protection:**
  - A Chapter 5 filing should include the provincial rate protection amounts for 2014 test year and all forecasted REG expenditures during the IRM period for Board approval:
    - Renewable Enabling Improvements 94%
    - Expansion 83%
    - Or file a study
  - A rate order to IESO includes:
    - Annual aggregate amounts charged to the IESO
    - An order to collect an aggregate monthly amount from all rate payers
    - A letter attached to the order directs the IESO to remit the amounts noted to the qualifying distributors in a timely manner

Appendix 2-FA: Renewable Generation Connection Investment Summary (over the rate setting period)

Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there is more than **five** project proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (pg 15, EB-2009-0349)

Part A

REI Investments (Direct Benefit at 6%)	2014	2015	2016	2017	2018
Project 1					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	$ -	$ -	$ -	$ -	$ -
Total OM&A (Start-Up)	$ -	$ -	$ -	$ -	$ -
Total OM&A (Ongoing)	$ -	$ -	$ -	$ -	$ -

Part B

Expansion Investments (Direct Benefit at 17%)	2014	2015	2016	2017	2018
Project 1					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	$ -	$ -	$ -	$ -	$ -
Total OM&A (Start-Up)	$ -	$ -	$ -	$ -	$ -
Total OM&A (Ongoing)	$ -	$ -	$ -	$ -	$ -

Appendix 2-FB: Calculation of Direct Benefits/Provincial Rate Protection

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	0%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	0%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	0%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	0.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	0.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE	0.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -			$ -

Note 1: Revenue collected from the IESO should be recorded in a variance account.

Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

Appendix 2-FB: PILs Calculation

PILs Calculation

Income Tax	**2014** Direct Benefit	**2014** Provincial	**2015** Direct Benefit	**2015** Provincial	**2016** Direct Benefit	**2016** Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up						
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -

Appendix 2-FB – Net Fixed Asset & UCC calculation

Net Fixed Assets

		2014	2015	2016	2017	2018
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		-	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC		$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -

Questions?

Ontario Energy Board

EB-2009-0349

Report of the Board

Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09

June 10, 2010

Table of Contents

EXECUTIVE SUMMARY

The *Green Energy and Green Economy Act, 2009* (the "Green Energy Act") amended the *Ontario Energy Board Act, 1998* (the "Act") to introduce a mechanism under section 79.1 whereby some of the Board-approved costs incurred by a distributor to make an *eligible investment* for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment.

To enable this rate protection provision, the Government filed Ontario Regulation 330/09 ("O. Reg. 330/09") which sets out details related to the implementation of the cost recovery framework established in section 79.1. O. Reg. 330/09 sets out the following formula:

A = B - C, where:

A = the amount of *rate protection* to be provided to prescribed consumers in a distributor's service area,

B = *eligible investment costs* determined by the Board to be the responsibility of the distributor in accordance with the DSC, and

C = the amount the Board determines to represent the *direct benefits* that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

The Board's first phase of determining cost responsibility (EB-2009-0077) was completed in October 2009 and determined the allocation of costs between generators and distributors.

Building on phase one, this Board framework allocates the non-generator costs between the ratepayers of the distributor making the investment and all provincial ratepayers. The direct benefits as determined by the Board will represent the allocation of costs to the ratepayers of the distributor making the investment.

The Board has identified two categories of direct benefits that accrue to the customers of the distributor making the investment to form the basis from which this allocation will be determined. Those direct benefits are comprised of:

1. surplus Network and Connection (renewable generation < 2 MW) transmission charges as well as surplus wholesale market service charges (WMSC); and
2. a portion of the Expansion and Renewable Enabling Improvement (REI) eligible investment costs.

For the first category of direct benefits, an *ex post* approach will apply to all distributors for the purpose of quantifying these benefits. Based on the actual production from qualifying renewable generation the previous year, the surplus transmission and WMSC charges collected by the distributor, as a consequence of new embedded renewable generation connected to eligible investments, will be determined to be a direct benefit that accrues to the customers of the distributor as a result of the eligible investments.

For the second category of direct benefits, the Board has adopted a two-pronged approach which recognizes the circumstances of distributors based on the amount of eligible investment. The Board will utilize the threshold in the Filing Requirements for Distribution System Plans (EB-2009-0397) to implement that two-pronged approach. Distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct benefit assessment, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment based on the principles and criteria set out in this Report. As such, in cases where there is relatively little incremental renewable generation connected, an approximation is justified based on a standardized approach, while a rigorous analysis is required where and when it is justified (i.e., disproportionate share of incremental renewable generation connections). For detailed direct benefit assessments, an *ex post* approach will also be the default for the purpose of quantifying this category of benefits.

The Board considers this approach to be transitional and evolutionary. A transitional approach that takes into account the following:

1. O. Reg. 330/09 which clarified the Board's responsibilities in this regard was issued relatively recently;
2. the relative magnitude of the eligible investment costs and, therefore, the associated direct benefits at this time[1]; and
3. the estimation of direct benefits in relation to such investments, for the purpose of establishing rates, is a new responsibility for the Board, particularly given the manner such generation will be connected which is unique to Ontario.[2] As a consequence, results from other jurisdictions cannot be directly applied to Ontario.

Over time, as material amounts of new renewable energy generation is connected across Ontario by different distributors, the Board expects there will be an opportunity to gain experience, in relation to quantifying the direct benefits, based on actual results. In doing so, as the Board, distributors and other participants in this consultation process

[1] The Rate Order for Hydro One Distribution (EB-2009-0096) sets out the approved amount to be provincially recovered in 2010 and it amounts to less than $0.46 million on a monthly basis from May 1, 2010 to December 31, 2010.

[2] In other jurisdictions (e.g., New Zealand), where benefits have been estimated, the local distribution companies were provided with more control over where distributed generation is connected and the type of generation (i.e., an appropriate balance between intermittent and non-intermittent generation) in a manner that allowed for the "optimization" of the network and the maximization of the benefits associated with distributed generation. In contrast, under the *Green Energy Act*, distributors will have an obligation to connect renewable generation facilities regardless of the location and type of generation.

attain a better understanding of the direct benefits (and costs), under the circumstances unique to Ontario, it should allow the Board to refine its approach in this regard.

The Board is of the view that the approach set out above strikes a reasonable balance between administrative burden and incremental precision.

1 INTRODUCTION

The *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"), which received Royal Assent on May 14, 2009, made a number of amendments to the *Ontario Energy Board Act, 1998* (the "Act"). Among these amendments, the Board has, as a new objective, to *"promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities"* (paragraph 5 of subsection 1(1) of the Act).

Consistent with its new objective of promoting the use and generation of electricity from renewable energy sources, the Board has reviewed the cost responsibility policies with respect to the connection of renewable energy generation to distribution systems. As a consequence, in EB-2009-0077, the Board issued final amendments (on October 21, 2009) to the Distribution System Code (the "DSC") in relation to *Distribution Connection Cost Responsibility* (the "DCCR Amendments") to revise its approach to assigning cost responsibility between an electricity distributor and a generator. For the purposes of assigning cost responsibility, the Board decided that such investments be classified within three general categories:

1. Connection assets (*generator* responsibility);
2. Expansions (*shared* responsibility based on a cost cap or *distributor* responsibility if identified in a Board-approved investment plan); and
3. Renewable enabling improvements (*distributor* responsibility).

The consequences of these changes in cost responsibility will mean that some of the costs related to connecting renewable generators – previously the responsibility of the connecting generator – will shift to ratepayers.

Evidence from the Renewable Energy Standard Offer Program ("RESOP") suggests that distribution-connected renewable energy generation development will not be distributed evenly among the service territories of the electricity distributors. As a result, in the absence of a cost-sharing mechanism, the cost burden of distribution system investment to accommodate the renewable generation would not be shared equally amongst distributors (and their ratepayers).

The *Green Energy Act* recognizes that some portion of such investment costs incurred by individual distributors should be shared amongst the province's ratepayers. Specifically, the *Green Energy Act* amended the Act to introduce a mechanism under section 79.1 whereby some of the Board-approved costs incurred by a distributor to make an '*eligible investment*' for the purpose of connecting or enabling the connection of a renewable energy generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor making the investment. (see Appendix 3 for full text of section 79.1). The structure of this rate protection provision closely resembles the provision in section 79 of the Act for Rural and Remote Rate Protection (“RRRP”).

To enable this rate protection provision, the Government filed Ontario Regulation 330/09 (“O. Reg. 330/09”) on September 9, 2009 which sets out details related to the implementation of the cost recovery framework established in section 79.1. That cost recovery framework establishes a process for the collection – by the Independent Electricity System Operator (“IESO”) – of the amounts that qualify for rate protection and a process for the IESO to make compensation payments to distributors based on the rate protection amounts as determined by the Board to which each distributor is entitled.[3] (see Appendix 4 for Regulation 330/09).

O. Reg. 330/09 sets out the following formula:

A = B - C, where:

A = the amount of *rate protection* to be provided to prescribed consumers in a distributor’s service area,

B = *eligible investment costs* determined by the Board to be the responsibility of the distributor in accordance with the DSC, and

C = the amount the Board determines to represent the *direct benefits* that accrue to prescribed consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

The Board’s DCCR amendments process addressed the first part of the formula (see “**B**” above) by determining the “eligible investment costs” and those include *Expansion* and *Renewable Enabling Improvement* investments, as described above.

The focus of this new Board policy entails completing the framework for determining the amount of rate protection to be provided by specifying the “direct benefits” component of the regulation formula (see “**C**” above).

The purpose of this framework is therefore to identify:

1. the direct benefits that must be taken into account by distributors; and
2. a standard methodology to be used by distributors in calculating or quantifying those direct benefits.

[3] Once the Board establishes the Aggregate Rate Protection amount, the Board will establish a rate that would be applied to all Ontario electricity customers of distributors in a manner that is consistent with the cost recovery framework set out in O. Reg. 330/09. The rate set by the Board will be a function of the Aggregate Rate Protection Amount and an IESO load forecast (AQEW + Embedded Generation). Under O. Reg. 330/09, the fixed annual rate set by the Board (included in the WMSC) will only be applied by distributors. The IESO will collect the actual amounts of ‘rate protection’ each month from Market Participants, including distributors, as determined by the Board (and pay out the exact same amount in Monthly Compensation Payments to distributors based on their share as set out by the Board). The IESO will therefore charge a different “notional” rate to Market Participants that varies each month (i.e., not fixed) with fluctuations in market consumption.

1.1 Regulation 330/09

As a consequence of the determination of the direct benefits, the cost allocation associated with eligible investments between provincial ratepayers and the ratepayers of the individual distributor making the investment will be determined. There is therefore a relationship between the eligible investment costs and the associated direct benefits. As such, a clear understanding of what constitutes an eligible investment is necessary before discussing the related direct benefits. The Board therefore wishes to set out its interpretation of the following in relation to O. Reg. 330/09.

- "Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also includes the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on the initial investment, *ongoing* OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery.

- The *Green Energy Act* focused on investments related to both the smart grid and the connection of renewable energy generation. However, O. Reg. 330/09 applies to only investments related to the connection of renewable energy generation in relation to being "eligible investments". As a result, unless a certain smart grid related investment has been identified in the DSC as a Renewable Enabling Improvement, such investments are not "eligible investments" for the purpose of the Act and the regulation.

- Not all investments made by a distributor to accommodate renewable generation will qualify as an "eligible investment". Investments to connect such generation that is contracted under the feed-in tariff ("FIT") program will be treated as an "eligible investment". However, similar investments to connect generation that was contracted under the RESOP program will not be treated as an "eligible investment". The important distinction is not between the two programs of the Ontario Power Authority (OPA). Instead, it is related to the Board's cost responsibility rules under the DSC and the timing of the recent DCCR amendments. RESOP generation was contracted before those DCCR amendments were made. As a consequence, investments to connect a RESOP generator remain the cost responsibility of the generator. In contrast, investments made by a distributor to connect FIT generators will occur after the Board issued its revised cost responsibility rules on October 21, 2009 and are therefore eligible for the provincial recovery mechanism.[4] As such, the "direct benefits" which are the focus of this Board framework only take into consideration

[4] Specifically, the Board's October 21, 2009 Notice of Amendment to the DSC (EB-2009-0077) identified that the new cost responsibility rules apply to investments associated with renewable generation projects for which an application to connect was made on or after October 21, 2009. Further details in relation to the date of application and a specific scenario are provided in that Board Notice.

those related to investments to connect renewable generation under the FIT program.[5] Such generation is referred to as 'qualifying' renewable generation in this report.

- Most *upstream* costs and benefits related to renewable generation connected in the distribution system will not be taken into account for the purpose of the Act and O. Reg. 330/09.

  - The Board's Notice (June 5, 2009) related to the DCCR Amendments (EB-2009-0077) states *"Some generation connections may trigger the need for upstream upgrades to the system of a host distributor or of a transmitter, in addition to triggering the need for the expansion of the distribution system to which the generation facility will be connected. Although the DSC is silent on the issue of cost responsibility for these upstream upgrades, the practice is for distributors to pass these costs on to the connecting generator. The Board does not propose to revise this approach at this time…".* Since such costs, which are related to another upstream entity, have been determined by the Board to be the responsibility of the generator, these investments would not be considered "eligible investments" under O. Reg. 330/09 and, as a consequence, would not be considered in determining the direct benefits.

  - Similarly, a potential *upstream* benefit often associated with distribution generation is related to the deferral or avoidance of certain transmission network investments. Such *upstream* benefits may be realized. However, these *upstream* benefits accrue to all provincial ratepayers – not only the customers of the distributor making the investment – and, therefore, will not be considered in this particular Board policy.

  - The only *upstream* benefits that will be taken into account for the purpose of the Act and O. Reg. 330/09 are in relation to transformers owned by the distributor undertaking the investment, as those benefits accrue to only the customers of the distributor making the investment.

1.2 The Consultation Process

The Board engaged stakeholders in a consultation to assist the Board in determining an appropriate framework for determining the direct benefits. To that end, the Board released a Staff Discussion Paper (the "Discussion Paper") for comment.

The Discussion Paper proposed the types of direct benefits to be taken into account as well as principles and criteria for the purpose of quantifying those direct benefits. The Discussion Paper also included a list of issues designed to elicit and facilitate comment.

[5] Any investment made by a distributor on or after October 21, 2009 to connect *merchant* renewable generation would also be considered an "eligible investment".

That list is set out in Appendix 1 to this Report. Among the issues the Discussion Paper identified were:

- whether the two types of direct benefits that were proposed are appropriate;
- whether any refinements should be made to the proposed criteria for the purpose of estimating the direct benefits;
- whether the Board should consider a certain standardized approach and, if so, what would an appropriate threshold be to determine which distributors could use the standardized approach and which distributors should be required to undertake a more rigorous assessment; and
- whether there are any information limitations that may prevent certain distributors from providing an assessment of any proposed criteria as described in the Discussion Paper.

As part of the initial comments, certain stakeholders expressed a desire for further discussion of the issues in advance of issuance of the Board's policy, as well as the opportunity for a second round of comments. The Board agreed that it would be beneficial to expand the scope of the consultation process to include further written comments and a Stakeholder Meeting to better inform that second round of comments.

The Board received written comments from the 13 stakeholders listed in Appendix 2 to this Report. Those stakeholders represent electricity distributors and ratepayers. The Board has benefited from these written comments in determining the framework set out in this Report, and thanks all stakeholders for their thoughtful input.

2 THE DISCUSSION PAPER AND OVERVIEW OF STAKEHOLDER COMMENTS

2.1 Types of Direct Benefits

The Discussion Paper proposed that the scope of the direct benefits be limited to those that meet the following criteria:

1. the benefit is directly attributable to only the customers of the distributor making the investment; and
2. the benefit is readily quantified in monetary terms.

On the basis of those criteria, the Discussion Paper also identified two types of direct benefits:

1. Reduced *Network* transmission charges and reduced wholesale market service charges (WMSC) realized by the distributor as a consequence of electricity production from new renewable generation connected by an eligible investment; and
2. Improved capabilities of the distribution system for load customers as a consequence of the eligible investments made by a distributor.

In regard to *Reduced Network Transmission and WMSC charges*, the Discussion Paper identified that, as additional renewable generation is connected to eligible investments within a distribution system and begins to produce power, it will reduce both the peak demand and the total quantity of energy withdrawn by the distributor. This, in turn, reduces these charges that must be *paid* by the distributor to the IESO. At the same time, there is no impact on the demand or quantity of energy consumed by that distributor's customers. As such, charges *collected* by the distributor do <u>not</u> decline. As a result, surplus network transmission and WMSC charges will be collected by the distributor which will be recorded in the distributor's applicable variance account and that surplus will ultimately be paid (i.e., disbursed) to only its customers.

In relation to the *Improved Capability of Distribution System for Load Customers*, the Discussion Paper identified that certain investments in the distribution system to accommodate additional renewable generation will also result in benefits for load customers of the distributor making the investment. Many of the eligible investments will convey energy to load customers as well as from renewable energy generation. For example, the investment may replace an asset that would have required replacement, in the near future, solely for the purpose of serving load customers.

Stakeholder comments on the Discussion Paper revealed general agreement in relation to the two criteria identified above for the purpose of determining the scope of direct benefits. There was, however, a clear difference of opinion between distributors and representatives of ratepayers in regard to whether the avoided charges should be included in the determination of the direct benefits. On the one hand, there was agreement that there would be a benefit to the customers of the distributor making the eligible investment (i.e., changes in revenue responsibility for these charges). On the other hand, ratepayer representatives believed that such avoided charges were a direct benefit and should be included, while distributors were of the view that the avoided charges were not a direct benefit within the context of O. Reg. 330/09. Some distributors therefore recommended that such benefits should, if the Board thought it necessary, be addressed in a separate Board proceeding.

A number of stakeholders also suggested that the avoided transmission charges should, in addition to the avoided Network charges, include avoided Connection charges associated with renewable generation under 2 MW. It was further suggested that the avoided charges related to microFIT generation should be excluded from the calculation given the administrative burden associated with tracking each microFIT project and the relatively small output.

2.2 Approach: Quantifying the Direct Benefits

For the first category of direct benefits, an *ex post* approach was proposed to apply to all distributors for quantifying these benefits. Based on the actual production from renewable generation the previous year, the surplus Network transmission and WMSC charges collected by the distributor, as a consequence of new embedded renewable generation connected to eligible investments, would be determined to be a direct benefit that accrues to the customers of the distributor as a result of the eligible investments.

For the second category of direct benefits, the Discussion Paper also proposed that a similar approach apply to all distributors at the outset. The methodology to derive those benefits would be based on the proposed principles and criteria discussed in section 3.3.2.1 of the Discussion Paper. The level of detail and analysis provided by a distributor would be commensurate with the circumstances of the distributor.

The Discussion Paper (section 3.3.2.2) also noted that the Board may wish to consider transitioning to a two-pronged approach with a less resource intensive standardized approach for certain distributors; specifically, in cases where there is relatively little incremental renewable generation connected, an approximation may be justified. The rationale in the Discussion Paper was the extreme diversity amongst the distributors in terms of the amount of generation capacity contracted in their territories under the RESOP program.[6] The Discussion Paper noted that, for the majority of distributors with a lower level of investment, undertaking a detailed analysis to estimate these benefits may result in administrative costs that represent a significant fraction of the benefit being estimated. However, the proposed standardized approach would be based on historical distributor results under the rigorous and detailed analysis associated with application of the principles and criteria discussed in section 3.3.2.1. The Discussion

[6] For example, under the RESOP program, 70% of the generation capacity was located in the territory of one distributor while 40 distributors each had less than 1% of the contracted capacity.

Paper therefore discussed the standardized approach within the context of a "Future Option" due to the fact that there were no historical results to draw upon. Within this context, the Discussion Paper also requested stakeholder input on a threshold to determine whether a distributor would be required to complete a detailed analysis or use the standardized approach.

Stakeholder comments on the Discussion Paper revealed general agreement that an *ex post* approach was appropriate, but that distributors should also have the option to use an *ex ante* approach if a variance account is used given all of the uncertainties associated with the timing and amount of renewable generation that will be connected under the OPA's FIT program. One distributor supported a pure *ex ante* approach (i.e., no variance account). However, one stakeholder identified that the wording in O. Reg. 330/09 appeared to not permit such a pure *ex ante* approach.

In first round of comments, there was almost full agreement with the Discussion Paper that a standardized approach should only be considered after sufficient experience had been gained. Only one distributor representative supported a standardized approach at the outset. However, the views of some stakeholders changed following the Stakeholder Meeting once there was a better understanding that the information available to assess direct benefits with accuracy was more limited than previously expected. The Hydro One distribution rate proceeding, where this issue was addressed, had also been completed. For example, one ratepayer representative noted in the second round of comments that they had a "major change in our thinking" and therefore suggested as part of the initial implementation that "the Board establish a default percentage for smaller utilities with limited resources or eligible investments instead of doing an expensive analysis that might not make any material difference".

In terms of a threshold, for determining whether a detailed analysis would be required or a standardized approach could be used, a ratepayer representative suggested adopting the threshold used by the Board in the Filing Requirements for when a Detailed GEA Plan is required (EB-2009-0397) and a distributor identified that it should be based on percentage of rate base to be consistent with other OEB guidelines.

2.3 Criteria Used to Assess Direct Benefits

While not explicitly stated in the Discussion Paper, the discussion of the criteria suggested project specific assessments would be necessary.

In terms of applying the criteria, one stakeholder noted that project specific assessments would be too costly and labour intensive and that a high-level approach should therefore be adopted. Another stakeholder acknowledged that, for certain distributors, a project specific approach could be somewhat onerous but, since most distributors will have a limited number of projects, a project specific approach should be readily applicable and that a cluster approach would yield a better estimate of direct benefits relative to a high level approach and reduce the level of detail required relative to project specific analysis for distributors with a large number of projects.

The criteria identified in the Discussion Paper for the purpose of estimating the direct benefits included the following:

1. Portion of Eligible Investments not used by Qualifying Generators
2. Customer Load Growth
3. Asset Condition
4. Size of Renewable Energy Generator(s)
5. Service Quality Improvement
6. Line Losses *(not included in assessment at outset)*
7. Alternative Criteria for Specific Investments *(optional)*

Of the stakeholders that commented on the following three criteria, there was general agreement that: (i) Line Loss impacts should be studied and not required at outset; (ii) Alternative Criteria for Specific Investments should be provided as an option that can be proposed by distributors; and (iii) Size of Renewable Energy Generator(s) should be eliminated as a separate criterion.

Distributors also identified information constraints in terms of three of the proposed criteria. With respect to the *Portion of Eligible Investments not used by Qualifying Generators* criterion and the *Service Quality Improvement* criterion, it was noted that no distributors have customer density information available at an area/regional level as proposed in the Discussion Paper. Similarly, in regard to the *Customer Load Growth* criterion, most distributors do not have such load growth information available at an area/regional level as proposed in the Discussion Paper.

The Service Quality Improvement criterion attracted the widest range of views including: it should be taken into account; it should only be taken into account for a couple of assets (SCADA for station automation and automated feeder reclosers); it should only be taken into account if it was already a planned investment for load customers of the distributors or if it was desired/wanted by the distributor's customers; and it should not be taken into account at all. Stakeholders also expressed concerns regarding the difficulty and/or ability to quantify the value of improvements in service quality/reliability to load customers.

In regard to the Asset Condition Criterion, one stakeholder noted that the statement in the Discussion Paper that an asset replaced early in its service life would not provide as great a benefit appeared to overlook an important consideration. That consideration is the residual value since distributors could use certain assets that are in good condition as a system spare or in another station. As such, the avoided cost of purchasing such a new asset for these purposes should be a direct benefit.

There was also general agreement that where provincial ratepayers provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. However, there was also agreement that it should not be reduced if the renewable generation does not materialize and the investment has not been used for other purposes.

3 THE BOARD'S APPROACH

The Board recognizes the need for a framework that recognizes the significant diversity of distributors in relation to the amount of renewable energy generation to be connected and the magnitude of the associated eligible investment. It also needs to recognize the current information limitations of distributors and strike a reasonable balance between administrative burden and incremental precision. The framework must be implemented in manner that is consistent with section 79.1 of the Act and O. Reg. 330/09, while protecting the interests of all ratepayers – ratepayers of the distributor making the investment and provincial ratepayers. The framework set out in this Report is therefore intended to be evolutionary in nature, with the expectation that the degree of precision will be enhanced in relation to quantifying the direct benefits as experience is gained and more information is acquired.

3.1 Identifying the Direct Benefits

As noted above, the Discussion Paper identified two criteria for the purpose of determining the scope of the direct benefits to be taken into account. The Board notes that those criteria are consistent with O. Reg. 330/09 as those criteria serve to exclude benefits which would accrue to all ratepayers across the province (e.g., environmental benefits) as well as *indirect* benefits such as local economic or fiscal impacts (e.g., additional local tax revenues).

The Board has therefore determined that the scope of the direct benefits will be limited to those that meet the following criteria:

1. the benefit is directly attributable to only the customers of the distributor making the investment; and
2. the benefit is readily quantified in monetary terms.

Based on those criteria, the Discussion Paper also identified two benefits to be used in determining the direct benefits that accrue to the prescribed customers of the distributor associated with eligible investments to connect new renewable energy generation.

The Board notes that, in terms of the types of benefits, the comments focused primarily on reduced network transmission charges and reduced wholesale market service charges (WMSC) realized by the distributor as a consequence of electricity production from qualifying renewable generation connected by an eligible investment.

The primary comment was to the effect that these reduced charges should not be considered a direct benefit under O. Reg. 330/09 as the focus should be on distribution costs or the distributor's revenue requirement. The Board notes that O. Reg. 330/09 makes no reference to distribution costs or revenue requirement and that there was agreement amongst all participants in this proceeding that there will be such a benefit to ratepayers of the distributor making the investment. The Board is of the view that, since provincial ratepayers will be required to pay some or all of the costs of the eligible investment needed to connect the qualifying renewable generation (from which this benefit is directly derived), it is appropriate that those provincial ratepayers should also share in the benefit that will be realized. In the absence of an eligible investment paid for by provincial ratepayers, this benefit would not exist. The Board is also of the view that this is the appropriate process to address this matter and that dealing with the issue in a separate Board process would be inefficient. The Board has therefore determined that these reduced charges will be included in the determination of the direct benefits that accrue to the prescribed customers of the distributor.

The Board also agrees with the comment that the reduced transmission charges should not be limited to Network charges. All charges that are subject to net load billing will result in a direct benefit. As such, a subset of Connection charges associated with renewable generation under 2 MW will also be taken into account.

The Board acknowledges the comment that microFIT generation should be excluded from the assessment of direct benefits for materiality reasons based on the relatively small output and the administrative burden associated with tracking each project. While the direct benefits associated with such generation will be immaterial at the individual project level, the Board believes there is the potential that it may become material over time at an aggregate level, particularly within the territories of certain distributors. The Board is therefore of the view that it is important to monitor microFIT generation at the outset in relation to its materiality and that period of time be used to ascertain whether a "rule of thumb" can be developed to minimize the administrative burden on distributors in the event the Board decides to include microFIT in the determination of direct benefits in the future.

The Board has therefore determined that the direct benefits to be taken into account by distributors are as follows:

1. Reduced *Network* and *Connection (renewable generation < 2 MW) transmission charges* as well as reduced *wholesale market service charges (WMSC)* realized by the distributor as a consequence of electricity production from new renewable generation connected by an eligible investment; and
2. Improved capabilities of the distribution system for load customers as a consequence of the eligible investments made by a distributor.

3.2 Quantifying the Direct Benefits

3.2.1 Reduced Network Transmission and WMSC Charges

The Discussion Paper identified two approaches – *ex ante* and *ex post* – for the purpose of estimating the direct benefits associated with reduced transmission and WMSC charges and proposed that an *ex post* approach be used by distributors.

The Board notes that section 3 of O. Reg. 330/09 refers to an eligible investment “made or planned to be made” by a distributor. This would support either an *ex post* or an *ex ante* approach. On the other hand, section 2 of O. Reg. 330/09 also describes the consumers eligible for rate protection as those served by a licensed distributor that has “incurred costs” to make an eligible investment that has been approved by the Board. This would clearly support an *ex post* approach. However, the Board believes that it would also support an *ex ante* approach, provided that the direct benefits are ultimately determined on the basis of costs that have been actually incurred. This is consistent with the approach taken by the Board in the proceeding to determine the 2010 and 2011 distribution rates for Hydro One (EB-2009-0096). Accordingly, while the Board believes that the *ex post* approach should be used by distributors, a distributor may use the *ex ante* approach on the condition that variance or deferral accounts are in place to allow for any reconciliation between forecast and actual benefits.

The Board acknowledges the concern expressed by distributors that the reduced charges will be difficult to track and that processes will need to be developed. The Board notes, however, that distributors are already required by the regulation pertaining to the Global Adjustment to submit production from embedded generation on a monthly basis to the IESO and that distributors will also be required to settle FIT contracts based on hourly data. The Board is therefore of the view that other processes are or will be in place to facilitate the calculation.

The Board also acknowledges the comment that the reduced allocated quantity of energy withdrawn (AQEW) of distributors from the grid due to embedded renewable generation will result in higher WMSC and transmission rates. However, the Board does not agree an expected higher rate should be used in the calculation of the direct benefits. To the extent these rates increase due to reduced withdrawals from the grid, it will equally affect all provincial ratepayers – not only the customers of the distributor making the investment. Distributors should therefore use the actual rates in place for the year the direct benefits are being determined.

The calculation of direct benefits in relation to reduced transmission and WMSC charges will be made by distributors based on the actual energy production from the qualifying renewable generation connected to eligible investments, and its contribution to reduced peak demand. Under the *ex post* approach, quantifying the annual benefits in this category for a given year will therefore be calculated by multiplying the actual rate (WMSC and transmission) by the actual renewable energy production from the *previous* year.

3.2.2 Improved Capability of Distribution System for Load Customers

3.2.2.1 Approach

The Discussion Paper proposed a framework for the estimation of the direct benefits related to this category. That framework was based on a number of principles and criteria to be taken into account by the distributor in estimating the benefits that will accrue to the customers of the distributor as a consequence of making the eligible investment(s). The Discussion Paper also proposed consideration of a less resource-intensive standardized approach for certain distributors. However, a standardized approach was only proposed as an option for implementation in the future due to the lack of historical results to use as a basis. Stakeholders generally agreed with this approach.

The Board believes that a two-pronged approach which recognizes the circumstances of distributors based on the amount of eligible investment is appropriate. However, the Board is of the view that, due to a number of factors, a standardized approach for certain distributors is appropriate at the outset of the implementation of this framework. The primary factor relates to the information limitations associated with the criteria identified in Discussion Paper that have come to the Board's attention during this consultation process. The Board has also recently issued a Partial Decision that addressed this matter in relation to Hydro One Distribution. As a consequence, the direct benefits cannot be estimated with the degree of precision previously expected and some historical results are now available as a basis for standardized approach that can be refined over time.

3.2.2.2 Threshold

On March 25, 2010, the Board issued its "Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence" (EB-2009-0397).[7] The Filing Requirements require that distributors file either a Detailed GEA Plan or a Basic GEA Plan depending on the materiality of planned system investments related to the connection of renewable generation or the development of a smart grid. Those Filing Requirements identify that such GEA Plans must be filed as part of a distributor's cost of service rate application for 2012 and subsequent rate years unless the Board directs otherwise. The Filing Requirements note that "the Board will issue a Report setting out a policy with respect to the calculation or quantification of direct benefits, and these Filing Requirements require that distributors provide information pertaining to direct benefits in a manner consistent with that policy".

For the purpose of this policy, the Board will adopt the threshold in the Filing Requirements for Distribution System Plans that is used to determine whether a distributor is required to file a Detailed or Basic GEA Plan.[8] As such, distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct

[7] Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397), March 25, 2010.

[8] Specifically, the materiality threshold currently set out in the Filing Requirements is:

1. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:
    - Are more than $100,000 and exceed 3% of the distributor's distribution rate base; or
    - Exceed $5,000,000.
2. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:
    - Are more than $100,000 and exceed 6% of the distributor's distribution rate base; or
    - Exceed $10,000,000.

benefit assessment as explained below, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment. However, if a distributor that files a Detailed GEA Plan falls below the threshold once all Smart Grid capital costs are excluded, that distributor will be permitted to use the standardized approach since Smart Grid costs are not relevant for the purpose of this framework.

Any distributor that is permitted to use the standardized approach will be provided with the option to undertake a detailed direct benefit assessment.

3.2.2.3 Basic Benefit Assessments for Basic GEA Plans

The Board will use an ongoing weighted average of actual direct benefits (relative to total eligible investment costs) associated with all distributors that have completed a detailed direct benefit assessment. As this is an evolutionary framework, it is the intent of the Board that the percentage used in the standardized approach will be refined over time as experience is gained and more distributors complete a detailed benefit assessment. For example, this may take the form of different percentages for different investments in the future.

At this time, only Hydro One Distribution has completed a detailed direct benefit assessment. The Board agrees with the comment that the Hydro One estimates of the direct benefits have an empirical basis and are based on a large number of projects, and therefore can be used as a transitional step in this evolutionary framework for distributors permitted to use the standardized approach. However, the Board does not believe the suggested use of a single percentage (i.e., 15%) for all eligible investments would be appropriate. The percentages of direct benefits differ for Expansion and Renewable Enabling Improvement (REI) investments, as Expansion investments tend to benefit load customers more than REI investments.[9] In addition, distributors will have different relative proportions of such investments. As such, separate percentages for Expansion and REI investments will be utilized to provide a more accurate estimate of the direct benefits.

Absent the information limitations identified during the consultation process, the Board would have been hesitant to use the Hydro One Distribution percentages of direct benefits in relation to REI and Expansion investments for other distributors. However, aside from the number of projects, the characteristic that differentiated Hydro One Distribution most from other distributors is customer density and it was learned in this consultation process that no distributors, including Hydro One, have such information specific to different areas in their service territories. The number of projects is also not a factor at all in the determination of direct benefits associated with an investment. As such, the Board is of the view that the percentages that are ultimately approved for

[9] For example, based on the provisionally approved methodology and allocation (i.e., dollar amounts) proposed by Hydro One as part of its 2010 and 2011 distribution rates application, those dollar amounts represent 6% for REI investments and 17% for Expansion investments.

Hydro One Distribution[10] in relation to Expansion and REI investments should provide a reasonable estimate for other distributors until more distributors complete detailed benefit assessments and a rolling weighted average can be used, particularly given the limited amount of eligible investments expected in Basic GEA Plans.

The Board has only approved the allocation of costs proposed by Hydro One, on a provisional basis, at this time. The Board's Partial Decision notes that "the allocation methodology and the resulting responsibility for Green Energy Plan costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349." As such, the percentages that are initially to be used by distributors undertaking a basic benefit assessment will be the percentages based on the methodology and allocation that are approved by the Board on a final basis subsequent to the issuance of this Board Report. Those revised percentages will be communicated by the Board when they become available.

As noted above, in the future, the Board will use an ongoing weighted average of actual direct benefits associated with all distributors that have completed a detailed direct benefit assessment. As the percentages are updated to reflect changes in this ongoing weighted average, the updated percentages will only apply to incremental eligible investments for which the Board has not yet determined the direct benefits. In other words, the Board will not make future adjustments to previous calculations of direct benefits that have already been approved by the Board to reflect changes in the weighted average.

Consistent with the Board's interpretation of O. Reg. 330/09 above, the calculation of this category of direct benefits will also be on either an *ex post* basis or on an *ex ante* basis with a variance or deferral account.

3.2.2.4 Detailed Benefit Assessments for Detailed GEA Plans

As noted above, distributors required to file a Detailed GEA Plan will be expected to undertake a detailed direct benefit assessment based on the principles and criteria set out below unless the total capital costs in the plan are below the threshold once all Smart Grid capital costs have been excluded.

<u>Guiding Principles</u>

The Board generally agrees with the principles that were identified in the Discussion Paper with some modifications to reflect certain stakeholder comments.

In relation to the first principle, the Board agrees with the comment that it is important to clarify "load" customers and "eligible" investments.

In regard to the second principle, a number of stakeholders commented that the circumstances of the distributor should not be related to the size of the distributor in

[10] EB-2009-0096.

determining the level of detail and analysis to be provided. The Board is of the same view and has therefore clarified that it will be the circumstances of the distributor in terms of the amount of qualifying renewable energy generation to be connected and the magnitude of the associated eligible investment.

The Discussion Paper identified in the fourth principle that if any asset is replaced to accommodate qualifying renewable generation, customers of the distributor making the investment would realize a direct benefit of some magnitude. A stakeholder comment noted that there are certain specific assets (e.g., conductors, pole-mount transformers) where this would not be the case. This will need to be determined by the Board in a hearing on an application. As such, the Board has clarified that a direct benefit is expected in such cases unless it can be demonstrated otherwise.

The other principles that were set out in the Discussion Paper remain unchanged.

The Board has therefore determined that the following guiding principles will provide the basis for the more detailed discussion of the criteria that follow.

1) The benefit is directly attributable to only the load customers of the distributor making the eligible investment (i.e., limited to distribution system investments) and the benefit is readily quantified in monetary terms.

2) The level of detail and analysis provided by a distributor underlying the estimation of the direct benefits should be commensurate with the circumstances of the distributor in terms of the amount of qualifying renewable generation to be connected and the magnitude of the associated eligible investment.

3) Portions of certain eligible investments may not ultimately be used by only qualifying renewable generation facilities to which the Board's new cost responsibility policies apply. Consistent with O. Reg. 330/09, to the extent the investment is used for other purposes (e.g., connect a large load customer), that portion of the investment would not be recovered through the provincial recovery mechanism.

4) Where any existing distribution asset is replaced to accommodate qualifying renewable generation, customers of the distributor making the investment will realize a direct benefit of some magnitude and therefore a certain portion of the costs should not be recovered through provincial recovery mechanism unless it can be demonstrated otherwise.

5) To the extent certain eligible investments (e.g., Renewable Enabling Improvements) that accommodate qualifying renewable generation are expected to improve service quality for the load customers of the distributor making the investment, such service quality improvements will represent a direct benefit to only the customers of that distributor (i.e., not paid for under the provincial recovery mechanism).

6) Distributors should not be required to estimate certain benefits (e.g., line losses) that may, in theory, sometimes be associated with distributed generation in a generic sense, but do not take into consideration the practical circumstances unique to Ontario under the *Green Energy Act*.

Criteria

The Board generally agrees with most of the criteria that were identified in the Discussion Paper. Some criteria have been changed to reflect the information limitations mentioned above while other changes have been made to reflect certain comments from stakeholders. One criterion has also been added – Avoided Asset Upgrades – and one criterion that was identified in the Discussion Paper has been removed as explained below.

As noted above, the Discussion Paper suggested project specific assessments would be necessary. The Board acknowledges the comment that project specific assessments could be costly and labour intensive to implement under certain circumstances. However, the Board agrees that a project specific approach should be readily applicable since most distributors will have a limited number of projects and that, for distributors with a large number of projects, a cluster approach would yield a better estimate of direct benefits relative to a high level approach and reduce the level of detail required relative to project specific analysis. As such, the distributor should, in its Distribution GEA Plan, use project specific assessments in the application of the criteria set out below as the default approach. However, where a distributor has a significant number of projects, that distributor will be permitted to use a cluster approach.

In relation to the criterion identified as "Size of Renewable Energy Generator(s)" in the Discussion Paper, the Board agrees with the comment that it is taken into account in the assessment of other criteria. As such, the Board has removed it as a separate criterion.

The Discussion Paper also identified a "Line Losses" criterion in noting that distributors should *not* be required to take this criterion into account in estimating the direct benefits at this time because, depending on the circumstances, line losses can either be reduced or increase due to distributed generation and the outcome is not certain in Ontario. The Board notes that Ontario's circumstances differ from most other jurisdictions as generators – not distributors – will be determining the point of connection and the distributor will therefore have no control in relation to the impact of the generator on line losses. The Board is therefore of the view that the impact on line losses is too uncertain at this time and that it will be in a better position to determine if such a criterion can be incorporated into the direct benefit assessment framework, with relative certainty and accuracy, once some experience has been gained in Ontario. The Board will consider carrying out a study in this regard once there is a material amount of distributed renewable generation in operation.

Given the above, the Board has determined that distributors should assess the direct benefits based on the first five criteria set out below. The sixth criterion is optional. A distributor should, in its Distribution GEA Plan, explain how they took each applicable criterion into account. Some of the criteria are only applicable to certain investments or certain circumstances.

1) Portion of Eligible Investments not used by Qualifying Generators

The Discussion Paper noted and the Board agrees that, to the extent this criterion is not appropriately taken into account, the distributor would derive two revenue streams for the same asset via distribution revenues or a capital contribution from its customers as well as ’compensation payments’ for ’rate protection’ purposes from provincial ratepayers. The Board is of the view that such an outcome would not be acceptable.

The Board notes that due to the fact that distributors do not have customer density information available at the area/regional level, customer density will not be taken into consideration in the assessment of this criterion as proposed in the Discussion Paper.

The distributor should, in its Distribution GEA Plan, estimate to what degree (i.e., share) the investment will be used by *load customers* (relative to qualifying renewable generators). The distributor should also estimate the portion of the investment that will be utilized by *non-qualifying generators*. This is not limited to non-renewable distributed generation that may be connected. It also includes renewable generation that has proceeded under a RESOP contract, as different cost responsibility rules apply under which the majority of the costs remain the responsibility of the connecting generator.

The Board acknowledges that the Discussion Paper did not specify a basis for determining the relative use of the eligible investment and that a common parameter should be used by all distributors. Various potential parameters were identified in the comments such as peak kW of output vs. peak kW of load (i.e., capacity), kWh of output vs. kWh of load (i.e., energy), etc. The Board also acknowledges that either energy or capacity could be used. However, the Board is of the view that capacity should be used by distributors. Investments are typically made on the basis of capacity and the use of energy would appear to entail greater complexity. The Board does not believe there would be incremental benefits or advantages that would flow from an alternative methodology that are sufficient to outweigh the added complexity.

There may be instances where the Board has determined an investment to be an eligible investment but circumstances resulted in the distributor subsequently utilizing the asset for other purposes (e.g., to connect load customers and/or non-qualifying generators). In such cases, the distributor should bring this to the attention of the Board and any direct benefits, which were not previously taken into account in an appropriate manner, should be applied by the distributor as a direct benefit to reduce future eligible investment costs of that distributor. The amount of rate protection will accordingly be reduced by the Board going forward. This may include the value of any rebates that are received by the distributor as proposed in the Board's March 11, 2010 Notice in relation to the EB-2009-0077 consultation process.[11] The Board notes, in cases where it is simply a matter that planned renewable generation has not been connected and the distributor has not used the asset for other purposes, there would be no direct benefits to take into account (i.e., no adjustments to rate protection would be necessary).

2) Customer Load Growth

The distributor should also estimate the extent to which an eligible investment might replace an investment that would otherwise be required to accommodate load growth. For example, in relation to an Expansion-related eligible investment involving new assets (e.g., a new distribution line), where load growth is relatively high, an expansion would have been required in the future even if there was not a new renewable generator to connect.

In applying this criterion, the load growth used should be as specific as the distributor has available to the area/region where the qualifying renewable generation will connect. This is most applicable to distributors with large service territories or distributors that have two or more non-contiguous regions included in its service area. The Board acknowledges that some distributors do not have load growth information available on an area/regional basis. In such cases, the distributor should use its system-wide load growth to estimate the direct benefits.

3) Asset Condition

Where an eligible investment is a replacement asset, the direct benefit to load customers of the distributor will depend on the condition and remaining useful life associated with the asset it replaces.

The Discussion Paper used the example of a 15 MVA transformer that may need to be upgraded to a 25 MVA transformer to accommodate qualifying renewable generation. The benefits to the customers of the distributor will depend, in part, on the remaining useful life of the 15 MVA transformer that was replaced. The Discussion Paper noted that, where the transformer would have required replacement in the near future, the direct benefits to the distributor's customers would be relatively significant. On the other hand, if the existing transformer was in good operating condition and was expected to have many years of service

[11] The Board's Notice (March 11, 2010) noted "Under the Proposed Rebate Amendments, there could be cases where a distributor obtains a rebate from an unforecasted customer after having already received compensation for the associated connection costs from consumers throughout the Province. Where the unforecasted customer is a non-renewable generator, for example, there is potential for the distributor to be compensated twice for the same cost. The Board expects to address this issue as part of its consultation on Rate Protection and the Determination of Direct Benefits under Ontario Regulation 330/09 (EB-2009-0349)."

remaining, the direct benefits would be expected to be relatively minor in most cases. However, a stakeholder noted and the Board agrees that where such an asset is in good operating condition, the distributor may be able to redeploy the asset as a system spare or use it in another location in its distribution system and therefore would avoid the cost of acquiring a new transformer in this example for such purposes. In such cases, the direct benefits would not be expected to be relatively minor.

The distributor should, in its Distribution GEA Plan, estimate the remaining useful life of the asset being replaced and therefore the extent it has deferred the need for future investment. The distributor should also estimate the avoided costs where the replaced asset can be redeployed.

Unless it can be demonstrated otherwise, where an asset is replaced, the Board expects that a certain portion of the costs would be allocated to the distributor's own customers, as a replacement asset will almost always extend the timeframe over which the asset would have needed to be replaced anyway and therefore represent a direct benefit.

4) Service Quality Improvements

Renewable Enabling Improvement investments can improve service quality to a distributor's load customers.

The Board notes that due to the fact that distributors do not have customer density information available at the area/regional level, customer density will <u>not</u> be taken into consideration in the assessment of this criterion as proposed in the Discussion Paper.

The Board acknowledges the comment that, if an investment results in an improvement in reliability or service quality, it should not be considered a direct benefit unless it was already a planned investment of the distributor for its load customers. However, the Board notes that O. Reg. 330/09 does not qualify the term direct benefit in any way. The Board is also of the view that it would not be appropriate to require provincial ratepayers to pay for any benefit that accrues to only ratepayers of the distributor making the investment.

Some stakeholders also identified that it is either very difficult or not possible to quantify the value associated with specific service quality improvements to load customers. The Board agrees that this would be too complex and would require a standard methodology that does not currently exist.

Until a more precise approach can be established, the Board believes that a relatively straightforward approach based on an estimate of the extent that load customers will use the investment relative to qualifying renewable generators should provide a reasonable estimate. The Board notes that there appears to be general agreement that the applicable REI investments are relatively limited. Two examples identified by stakeholders were SCADA for Distribution Station automation and automated feeder reclosers. As an example, Hydro One took such an approach in its application in relation to SCADA for Distribution Station automation. Hydro One estimated the percentage of Distribution Stations to be modified to accommodate renewable generation that should be monitored regardless of the generation and then applied an equal sharing to that subset of Distribution Stations between load customers and renewable generation to estimate the direct benefit.

The Board notes that, in cases where an investment is needed to prevent deterioration in reliability or service quality due to the connection of renewable generation, it should not be considered a direct benefit.

5) Avoided Asset Upgrades

The Board notes that the Discussion Paper focused on transmission assets in stating that upstream assets are not applicable to this policy. A stakeholder pointed out and the Board agrees that the injection of generation within a distributor's system can forestall the need to increase capacity at existing distributor-owned transformation stations. As a result, the distributor may avoid capital and OM&A costs associated with a larger transformation station and the value of such avoided costs should be considered as a direct benefit.

The distributor should, in its Distribution GEA Plan, estimate the avoided capital and OM&A costs in cases where such asset upgrades are avoided.

6) Alternative Criteria for Specific Investments

While the Board expects applying the applicable general criteria above in a similar manner to all eligible investments to be the most practical approach for distributors, certain selected asset investments may be more amenable to a benefit evaluation based on an alternative criterion (i.e., may not take any of the above criteria in account). If a distributor feels that another criterion would result in a more accurate estimate of the benefits, the distributor may propose such a criterion. The Board expects that this would be the exception rather than rule and that the distributor would explain why the alternative criterion was more appropriate in that particular instance.

Appendix 1: *Consultation – List of Issues*
Appendix 2: *List of Stakeholders*
Appendix 3: *Section 79.1 - Ontario Energy Board Act, 1998*
Appendix 4: *Full Text of Ontario Regulation 330/09*

Appendix 1:

Consultation – List of Issues

Section		Issues for Comment
3.2	**Identifying the Direct Benefits**	1) In addition to the two types of direct benefits identified above (i.e., reduced transmission and WMSC charges, improved capability of the distribution system), should the Board take into account any other direct benefits that accrue to customers of the distributor making the investment?
3.3	**Quantifying the Direct Benefits**	**Reduced Network Transmission and WMSC Charges** 2) Are there any circumstances under which a distributor should be permitted to deviate from the proposed *ex-post* approach and use an *ex-ante* (i.e., forwarding looking forecast) approach?
		Improved Capability of the Distribution System for Load Customers *Proposed Guiding Principles* 3) Are there any potential refinements to the proposed Guiding Principles discussed above? 4) Should any additional Guiding Principles be considered by the Board?
		Proposed Criteria 5) Are there any potential refinements to the proposed criteria discussed above for the purpose of estimating the direct benefits? 6) Are there any other criteria that the Board should potentially take into consideration or should certain criterion listed above not be taken into account? In proposing the addition and/or elimination of certain criteria, a solid business case should be made for the Board to consider the merits. 7) Is a ranking or weighting of the criteria above necessary? If so, please propose an appropriate ranking or weighting, from most to least applicable, and provide a supporting justification. 8) Are there any information limitations that may prevent certain distributors from providing an assessment of any criteria above?

Section		Issues for Comment
3.3	**Quantifying the Direct Benefits (cont'd)**	*Proposed Criteria (cont'd)* 9) In the absence of having the best available information possible (e.g., recently completed study), are there any factors above for which a distributor would not be able to provide a reasonable estimate? 10) What information should all distributors already have on hand (e.g., for distribution planning) that would allow for a reasonable estimate that is specific to certain areas of a distributor's territory of: (1) load growth; and (2) customer density? 11) Where provincial ratepayers have provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, Board staff proposed that the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. In such cases, are there any circumstances under which the amount of rate protection provided by provincial ratepayers should not be reduced? If so, please explain.
		Potential Future Option 12) Should the Board consider a certain standardized approach? If so, how should the approach be standardized? 13) Would a certain percentage of expansion investments and a certain percentage of REI investments (using a historical "baseline" specific to each distributor) provide a reasonable estimate on a go forward basis? 14) If the Board decided a standardized approach would be appropriate for certain distributors: (i) What *timeframe* would be suitable for implementation? (ii) What would an appropriate *threshold* be to determine which distributors could proceed under a standardized approach and which distributors should be required to continue under the more rigorous assessment discussed in section 3.3.2.1?

Appendix 2:

List of Stakeholders

The December 14, 2010 Staff Discussion Paper ("Discussion Paper") on the *Proposed Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* is available on the Board's web site at:

http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Rate+Protection+-+Determination+of+Direct+Benefits

Below is the list of stakeholders that provided written comments on the Discussion Paper. Both rounds of comments can be found on the same web page as the Discussion Paper.

- Association of Major Power Consumers in Ontario (AMPCO)
- Coalition of Large Distributors (CLD)
- Canadian Manufacturers & Exporters (CME)
- Consumers Council of Canada (CCC)
- Electricity Distributors Association (EDA)
- Energy Probe
- Enwin
- Federation of Ontario Cottagers' Association (FOCA)
- Hydro One Networks
- London Property Management Association (LPMA)
- Power Workers Union (PWU)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

Appendix 3:

Section 79.1: Ontario Energy Board Act, 1998

Cost recovery, connecting generation facilities
79.1 (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Distributor entitled to compensation re lost revenue
(2) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1) that is associated with costs that have been approved by the Board and incurred by the distributor to make an eligible investment referred to in subsection (1).

Consumers' contributions
(3) All consumers are required to contribute towards the amount of any compensation required under subsection (2) in accordance with the regulations.

Regulations
(4) The Lieutenant Governor in Council may make regulations,

- (a) prescribing consumers or classes of consumers eligible for rate protection under this section;
- (b) prescribing criteria to be met by a qualifying generation facility;
- (c) prescribing the criteria to be satisfied for an in-vestment to be an eligible investment;
- (d) prescribing rules for the calculation of the amount of the rate reduction;
- (e) prescribing maximum amounts of the total annual value of rate protection that may be provided under this section;
- (f) prescribing rules respecting the amounts that must be collected to compensate distributors, including rules,
  - (i) respecting the calculation of those amounts,
  - (ii) establishing the time and manner of collection,
  - (iii) requiring the amounts to be paid in instalments and requiring the payment of interest or penalties on late payments,
  - (iv) prescribing methods of ensuring that the amounts required cannot be bypassed, and
  - (v) respecting the distribution of the amounts collected;
- (g) prescribing the powers and duties of the Board in relation to the calculation of amounts to be collected and the time and manner of collection and distribution;

Definitions
(5) In this section,

"eligible investment" means an investment in the construction, expansion or reinforcement of a distribution line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less that meets the criteria prescribed by regulation;

"qualifying generation facility" means a generation facility that meets the criteria prescribed by regulation.

Appendix 4:

Full Text of Ontario Regulation 330/09

Definitions and interpretation

1. (1) In this Regulation,

"consumer" has the same meaning as in the *Electricity Act, 1998*;

"embedded distributor" means a licensed distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a licensed distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a licensed distributor who is a market participant and who distributes electricity to another licensed distributor who is not a market participant;

"licensed distributor" means a distributor who is licensed under Part V of the Act;

"qualified distributor" means a distributor serving consumers or classes of consumers that are being provided rate protection pursuant to subsection 79.1 (1) of the Act in accordance with this Regulation;

"rate protection" means rate protection under section 79.1 of the Act.

(2) The prescribed criterion for falling within the definition of an "eligible investment" under subsection 79.1 (5) of the Act is that the costs associated with the investment are determined to be the responsibility of the distributor in accordance with the Board's Distribution System Code.

(3) The prescribed criterion for falling within the definition of a "qualifying generation facility" under subsection 79.1 (5) of the Act is that the generation facility satisfies the criteria necessary to be a renewable energy generation facility under the *Electricity Act, 1998*.

Consumers eligible for rate protection

2. Consumers or classes of consumers are prescribed consumers or classes of consumers for the purposes of subsection 79.1 (4) of the Act if they are served by a licensed distributor that has incurred costs to make an eligible investment that has been approved by an order of the Board.

Calculation of rate protection

3. (1) The Board shall calculate the annual amount of rate protection to be provided to prescribed consumers or classes of consumers using the following formula:

$$A = B – C$$

where,

A is the amount of rate protection to be provided to prescribed consumers or classes of consumers in a distributor's service area,

B is the costs associated with the eligible investment described in subsection 1 (2), and

C is the amount that the Board determines to represent the direct benefits that accrue to prescribed consumers or classes of consumers as a result of all or part of the eligible investment made or planned to be made by the distributor.

(2) The Board shall calculate a monthly amount of compensation, referred to as the distributor's monthly compensation amount, to which each qualifying distributor is entitled, which amount shall be based on the amount calculated under subsection (1).

(3) Where the Board provides rate protection for a qualified distributor's prescribed consumers or classes of consumers, the Board shall, as often as is necessary and no less frequently than annually, calculate an aggregate monthly compensation amount by aggregating the amounts calculated under subsection (2) for each qualified distributor for each month for which collection is required.

(4) The Board shall, as often as is necessary and no less frequently than annually, calculate the monthly amount to be collected by the IESO under subsection 4 (2), such that the total amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(5) The Board shall, as often as is necessary and no less frequently than annually, calculate the amount of the charge to be collected by each distributor under subsection 4 (3) for each kilowatt hour of electricity that is distributed to a consumer or embedded distributor, such that the total forecasted amount that is to be collected is equal to the total amount of rate protection that is to be provided.

(6) In any year, if the amounts collected by distributors in accordance with subsection (5) are greater or less than the amounts calculated under subsection (3), the excess or shortfall shall be considered by the Board in calculating the amount of the charge that is to be collected by distributors under subsection (5) for the following year.

(7) Qualified distributors and persons to whom this Regulation applies shall provide the information relating to this Regulation that the Board requires, in a form and within the time specified by the Board.

IESO calculation of proportional share

4. (1) On a monthly basis, the IESO shall collect from market participants the amount calculated by the Board under subsection 3 (4) based on each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid, as determined in accordance with the Market Rules, where the electricity is for the use of consumers within Ontario.

(2) For the purposes of subsection (1), the IESO shall proportionately charge market participants based on the total of the net volume of electricity withdrawn by the market participants from the IESO-controlled grid during the month and, if the market participant is a licensed distributor, the sum of,

(a) the total volume of electricity supplied by embedded generators during the month to the market participant, adjusted for losses as required by the Retail Settlement Code; and

(b) the total volume of electricity supplied by embedded generators during the month to all embedded distributors for whom the market participant is the host distributor, adjusted for losses as required by the Retail Settlement Code.

(3) On a monthly basis, each distributor shall collect from each consumer in its service area and from each embedded distributor to which it distributes electricity an amount proportionate to the volume of electricity distributed to the consumer or to the embedded distributor, including the total volume of electricity supplied by embedded generators to embedded distributors in the host distributor's service areas in the manner described in clause (2) (b).

(4) A distributor who bills a consumer from whom the distributor must collect an amount in accordance with subsection (3) shall aggregate the amount that the consumer is required to contribute to the compensation required under subsection 79.1 (2) of the Act and this Regulation with the amount otherwise payable by the consumer in respect of the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on May 11, 2005.

IESO, monthly payments

5. (1) The IESO shall make a monthly payment to each qualified distributor that is equal to the monthly compensation amount determined by the Board under subsection 3 (2), including any payments for an embedded distributor to which the distributor delivers electricity.

(2) On a monthly basis, a host distributor shall, for each embedded distributor to which the host distributor distributes electricity, adjust the accounts between the host distributor and the embedded distributor by crediting the amount calculated by the Board under subsection 3 (2) to the embedded distributor.

(3) Payments required by this Regulation between licensed distributors and the IESO may be made, at the option of the IESO, by way of set off in the accounts maintained by the IESO.

(4) Payments required by this Regulation between an embedded distributor and its host distributor may be made, at the option of the host distributor, by way of set off in the accounts maintained by the host distributor.

IESO to provide certain information

6. (1) For the purpose of calculating the amounts referred to in subsection 3 (5), at least 60 days before the end of each calendar year the IESO shall submit to the Board,

(a) a forecast of the number of net kilowatt hours of electricity that are expected to be withdrawn from the IESO-controlled grid, as determined in accordance with the market rules, for use by consumers within Ontario during the IESO's next fiscal year;

(b) a forecast of the total volume of electricity that is expected to be supplied to distributors and embedded distributors by embedded generators;

(c) documentation supporting the forecasts referred to in clauses (a) and (b);

(d) a calculation of the total amount of excess or shortfall held in variance accounts maintained by distributors resulting from the difference between the amounts charged to distributors by the IESO and the amounts collected from consumers by distributors;

(e) documentation supporting the calculation referred to in clause (d); and

(f) such other information as the Board may require for the purposes of this Regulation, in the form specified by the Board and before the expiry of the period specified by the Board.

(2) The forecast referred to in clause (1) (a) shall be derived from information submitted to the Board by the IESO pursuant to section 19 of the *Electricity Act, 1998* in respect of the IESO's next fiscal year.

(3) At the end of each calendar year, the IESO shall submit to the Board the figures for the total amount of the monthly compensation that was paid out to each qualified distributor for each month of the year.

(4) Each distributor who is a market participant shall give the IESO such information as the IESO may require from the distributor for the purposes of this Regulation and shall do so in the

form specified by the IESO before the expiry of the period specified by the IESO. O. Reg. 330/09, s. 6 (4).

(5) Each embedded distributor shall give its host distributor such information as the IESO may require from the host distributor for the purposes of this Regulation and shall do so in a form specified by the host distributor before the expiry of the period specified by the host distributor.

Reliance on information

7. (1) For the purposes of this Regulation, the IESO shall rely on the information provided to it by each distributor who is a market participant.

(2) For the purposes of this Regulation, host distributors shall rely on the information provided to them by their embedded distributors.

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Exhibit 2 - Rate Base

Christie Clark, Project Advisor, Electricity Rates
July 24, 2013

Introduction

- Chapter 5 describes the planning and documentation for distribution system plans.
- Chapter 2 Exhibit 2 describes the rate-making requirements for including distribution system plans in a cost of service application.
- The capital costs in the documentation filed per Chapter 5 must be consistent with those included in Exhibit 2.

New Appendices

- Appendix 2-AB (Capital Expenditure Summary)
    - Table 2 from Chapter 5
- Appendix 2-BB (Service Life Comparison)
    - Kinectrics Report
- Appendix 2-G (Service Reliability Indicators)
    - Not a new requirement
  - List excludes new appendices discussed in other presentations

Overview

- Definitions
- Assets and Book Values
- Depreciation
- Working Capital Allowance
- Capital Expenditures (“CAPEX”) Program
- Incremental Capital Module (“ICM”)
- Stranded Assets
- Quality & Reliability Reporting

Definitions

- **Half Year Rule:** Recognizes that assets are added throughout the year and assumes that all are added at mid year. Is the average of the opening and closing balances for the fiscal year. Applies to NBV and depreciation expense.
- **Average of Averages:** For the purposes of rate base, it is the average of the monthly averages for a fiscal year ((1/2 the opening balance of the 1st month, the total of the remaining 11 months' opening balances + ½ the 12th month's closing balance) ÷ 13)

Assets and Book Values

- Appendices 2-A & 2-B series help in providing the asset related rate base evidence.
- Applicant must calculate and submit the rate base underpinned by the Appendices. (they must be reconciled if there are differences)
- The Appendices and rate base exhibits must include:
    - Historical Board-approved vs. Historical Actual (for most recent historic Board-approved year);
    - Historical Actual vs. preceding Historical Actual (for the relevant number of years);
    - Historical Actual vs. Bridge; and
    - Bridge vs. Test Year.

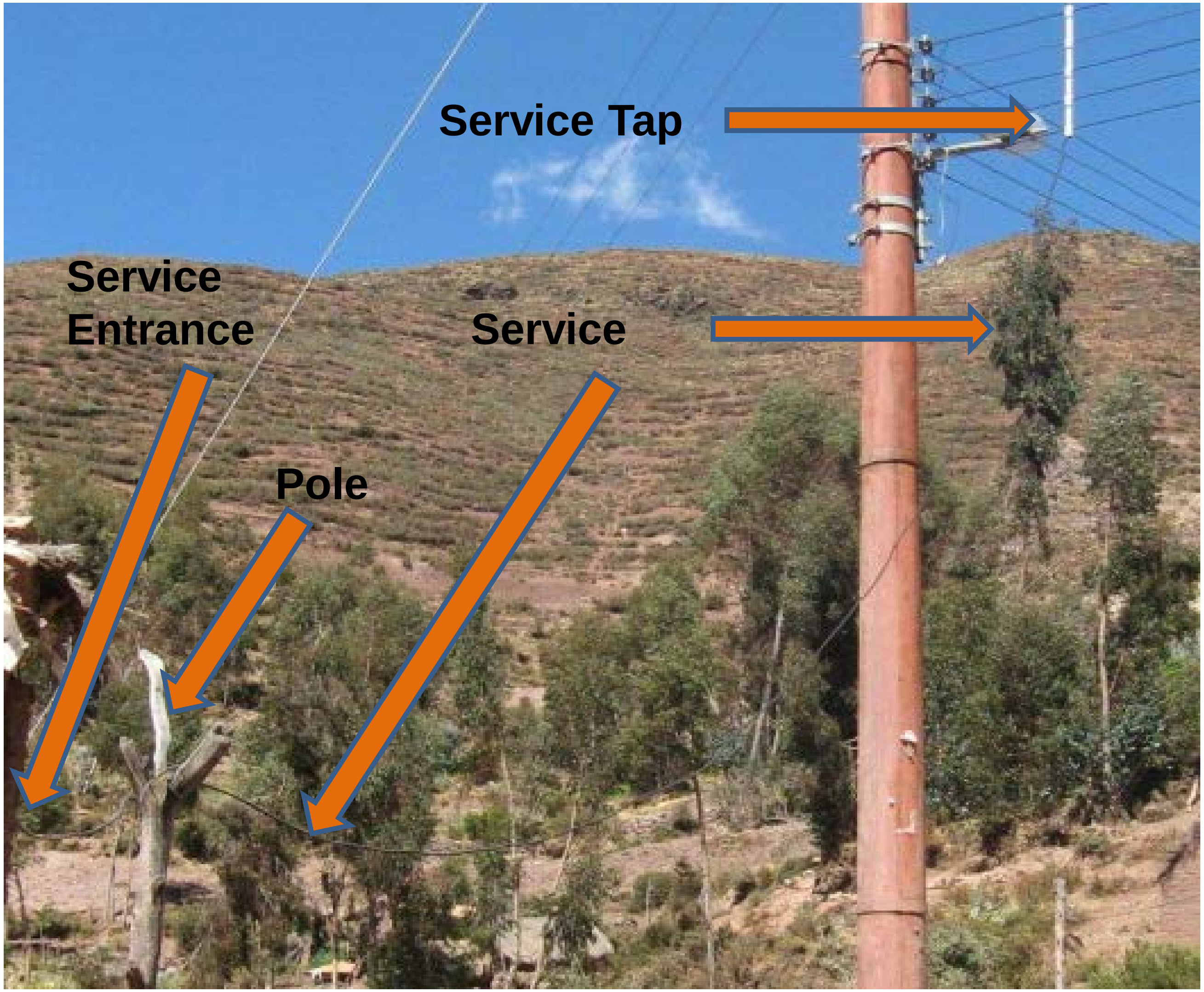
Assets and Book Values

Land and Structures

Assets and Book Values

Vehicles

Assets and Book Values



Assets and Book Values

- Sec. 2.5.1.1 states that the opening and closing balances must be provided.
- For the “Bridge Year”, the actuals to date and the “estimate” for year-end is required.
    - Be prepared to update the Bridge Year and how it flows into the test year through IRs.
- Include interest during construction and all overheads.
- Provide variance analysis and explanations for variances that are greater than the materiality threshold.
- Any restatements of balances must be reconciled to the previous balances and explanations provided.

Assets and Book Values

- Gross Assets – PP&E
- Summarize by function (distribution, general, other)
- Detailed breakdown by major plant account for each function
- Written description for each test year major plant account
- Detailed summary of any approved Incremental Capital Module from a previous 3rd generation IRM
- Include smart meters in opening 2014 account balances and provide a reconciliation to the 1555 DVA.

Assets and Book Values

- Appendix 2–B - Big Picture Overview:
- There are two types of 2-B appendices;
- CGAAP/ASPE/USGAAP, or
- MIFRS Transition year.
- For CGAAP, Appendix 2-BA should reconcile with Appendix 2-YB for 2013 and 2014.
- For MIFRS, Appendix 2-BB should reconcile to 2-YA

Depreciation

- Depreciation rates now must reflect the condition of the asset group and set to recover NBV over the estimated remaining life of the asset group.
  - Perform your own asset condition study, or
  - Use KINECTRICS Study as a starting point. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf
- Straight Line Remaining Life Depreciation Rates
  - Constant rate applied to gross assets.
- Test year depreciation expense as a cost of operations calculated in Appendix 2-C_ should be the depreciation in the continuity schedule Appendix 2-B_

Depreciation (as an aside)

- This approach increases the details required going forward to calculate reasonably appropriate rates from what has been kept in the past.
- Should be grouped into “symbiotic” asset types (i.e. when a pole line is retired, so are the attachments and the power cable.)
- Should be grouped by vintage – provides a $ weighted average.
- Include contributions.
- *Perhaps it could be linked to the asset management system/GPS system.*

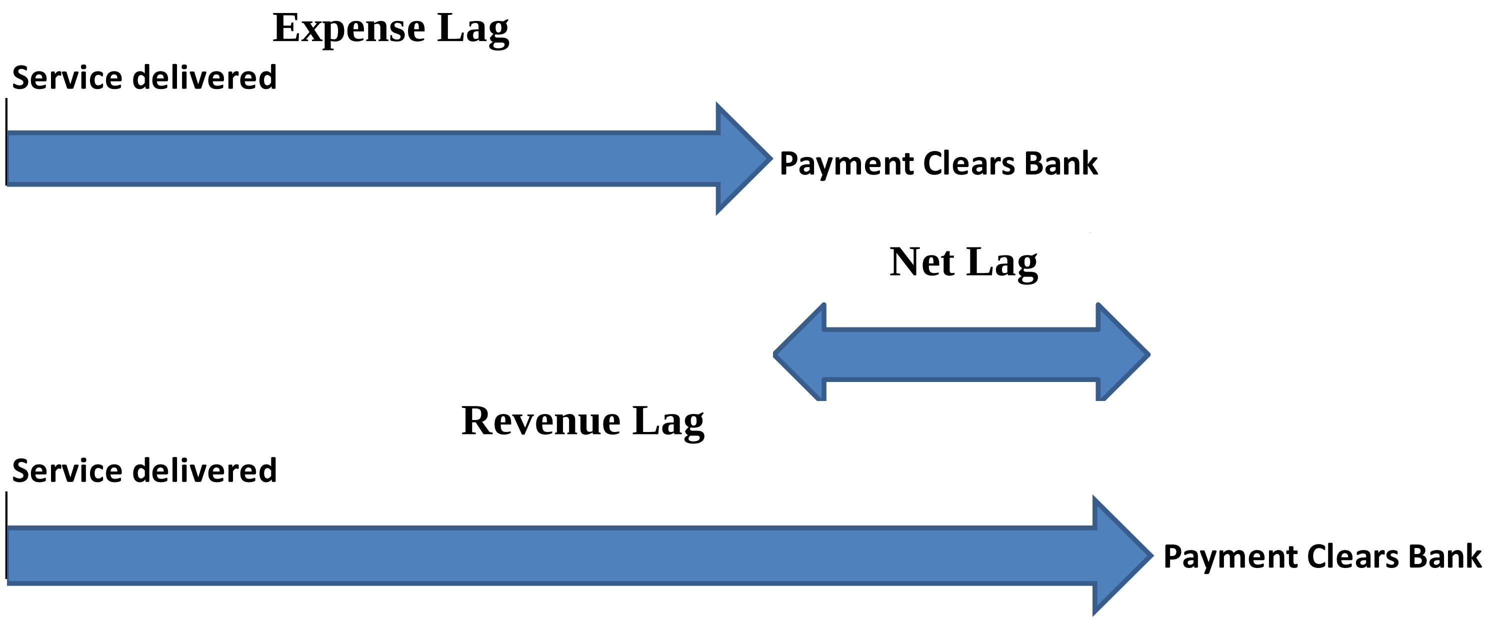
Working Capital Allowance

- Applicant may choose one of two means mentioned in Chapter 2 for estimating an allowance to be included in rate base for working capital:
  - Formulaic 13%; and
  - Lead-Lag Study.
- Formulaic approach applies 13% to:
  - Controllable OM&A expenses; and
  - Estimated Cost of Power in the Test Year.

Working Capital Allowance; Lead-Lag Study

- A lead-lag study is premised on the fact that, at start-up, a business has no revenues to meet its cash needs.
- Therefore a reserve of cash must be financed.
- The study analyses outflows on a dollar weighted basis.
- The study also analyses cash inflows on a dollar weighted basis.

Working Capital Allowance; Lead-Lag Study



CAPEX Program

- Subject to Chapter 5 requirements.
- The consolidated distribution system plan should be a stand alone document.
- Appendix 2-AA must be completed for the past 5 historical years, the bridge year and the test year.
- Treatment of contributions must be shown.
- Avoid classifying significant additions as miscellaneous.

CAPEX Program

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis							
Project Name #1							
Sub-Total	0	0	0	0	0	0	0
Project Name #2							
Sub-Total	0	0	0	0	0	0	0
Project Name #3							
Sub-Total	0	0	0	0	0	0	0
Project Name #4							
Sub-Total	0	0	0	0	0	0	0
Miscellaneous							
Total	0	0	0	0	0	0	0

CAPEX Program

- Explanations of variances from project budgets including variance from Board approved CAPEX.
- Explain the proposed accounting treatment including the any interest or other costs for the funds for projects with a life cycle greater than a year.
- Provide details for all other expenditures (non-distribution).
- Reconcile to total capital budget.
- Provide details of the capitalization policy and details of any changes to the policy, with specific references to depreciation and capitalization of overheads.
- Provide the overhead burden rates and explain any changes to them.

ICM

Addition of Assets in an ICM.

- Provide actual to Board approved variance analysis with detailed explanation.
- May want to propose whether a true-up is appropriate
- File related account balances and reconciliations for:
  - Account 1508 Other Regulatory Asset, Sub-account, Incremental Capital Expenditures
  - Account 1508 Other Regulatory Asset, Sub-account, Depreciation Expense
  - Account 1508 Other Regulatory Asset, Sub-account, accumulated Depreciation; and
  - Account 1508, Other Regulatory Asset, Sub-account, Incremental Capital Expenditures Rate Rider.

Stranded Assets

- Arise from smart meters, but could also be extenuating situations.
- Must file a proposal that conforms with the Board’s approach:
  - Remove the estimated NBV of the stranded meters from rate base as of December 31, 2013 (Appendix 2-S).
  - The total estimated NBV of the stranded meters must be recovered through separate rate riders for the applicable customer classes.
  - The total estimated stranded meter costs must be tracked in “Sub-account Stranded Meter Costs” of Account 1555;
  - The associated recoveries from the separate rate riders must also be recorded in this sub-account to reduce the balance in the sub-account.

Stranded Assets

- If smart meter deployment is not completed or not expected to be completed as of December 31, 2013:
  - Provide a stranded meter estimated cost.
  - Residual balance to be reviewed in next CoS application.
- Any proposed alternative to the above requires a complete explanation justifying the approach.

Quality & Reliability Reporting

- New Service Quality Requirements based on Chapter 7 of the DSC:
  - Connections/Reconnect;
  - Appointments;
  - Telephone;
  - Emergency Response
- Report for the last 5 years;
- Provide an explanation and actions to be taken, or taken for under-performance;
- Report outcomes.

Quality & Reliability Reporting

- Change in SRI Requirements:
  - No longer required to report CADI;
  - New Appendix 2-G;
  - Provide an explanation and actions to be taken, or to be taken for performance outside the established range.
  - Report outcomes.

Appendix 2-G
Service Reliability Indicators
2008 - 2012

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
SAIDI										
SAIFI										

5 Year Historical Average

SAIDI				
SAIFI				

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Questions?

Ontario Energy Board
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Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Setting Rates on Modified International Financial Reporting Standards ("MIFRS")

Daria Babaie, Manager, Regulatory Audit & Accounting
Fiona O'Connell, Project Advisor, Regulatory Audit & Accounting
July 24, 2013

Agenda

1. Modified IFRS (“MIFRS”)
2. 2014 Filing Requirements – MIFRS
   - MIFRS Appendices
3. Common Pitfalls from Prior Years’ MIFRS Applications
4. Questions

2.3.2 Accounting Standards

- The applicant should specify the accounting standard that is used in preparation of its application filed for the test year, e.g., 2014 or 2015.
  - e.g., if MIFRS has been used as the accounting basis of the application, the applicant must clearly state this in its application.

- For those applicants that have already adopted IFRS for financial reporting purposes or will adopt IFRS for financial reporting purposes effective January 1, 2014 (if test year is 2014 or 2015) or January 1, 2015 (if test year is 2015), cost of service applications must be filed on the basis of MIFRS.

What is MIFRS?

- What is MIFRS?
  - IFRS accounting as modified for regulatory purposes
- Greater consistency in measurement of rate impacts
  - Capitalization practice
  - Calculation of depreciation expenses

Key References for Interpreting Filing Requirements

- Report of the Board: Transition to IFRS, July 2009 – policy
  - Key areas impacted
  - Electricity and gas distributors, implications for others
  - Regulatory accounting policies, application filing requirements, Reporting & Record-keeping Requirements
- Asset Depreciation Study for the Ontario Energy Board – Kinectrics July 8, 2010
- Addendum to Report of the Board: Implementing IFRS in an IRM Environment June 13, 2011
- July 17, 2012 Board Letter
- June 25, 2013 Board Letter

MIFRS Application Filing for the 2014 or 2015 Rate Year

2014 Test Year

		Date of Adoption of IFRS for Financial Reporting Purposes:		
		January 1, 2012	January 1, 2013	January 1, 2014
Information Required to be Filed in 2014 CoS Application:	2010 H & Prior	CGAAP	CGAAP	CGAAP
	2011 H	MIFRS & CGAAP	CGAAP	CGAAP
	2012 H	MIFRS	MIFRS & CGAAP	CGAAP
	2013 B	MIFRS	MIFRS	MIFRS & CGAAP
	2014 T	MIFRS	MIFRS	MIFRS
Date of Transition to IFRS		January 1, 2011	January 1, 2012	January 1, 2013

H - historic year regulatory financial information
B - bridge year regulatory financial informaiton
T - test year regulatory financial information
(green box) Year in which both CGAAP and MIFRS information required

2015 Test Year

		Date of Adoption of IFRS for Financial Reporting Purposes:			
		January 1, 2012	January 1, 2013	January 1, 2014	January 1, 2015
Information Required to be Filed in 2015 CoS Application:	2010 H & Prior	CGAAP	CGAAP	CGAAP	CGAAP
	2011 H	MIFRS & CGAAP	CGAAP	CGAAP	CGAAP
	2012 H	MIFRS	MIFRS & CGAAP	CGAAP	CGAAP
	2013 H	MIFRS	MIFRS	MIFRS & CGAAP	CGAAP
	2014 B	MIFRS	MIFRS	MIFRS	MIFRS & CGAAP
	2015 T	MIFRS	MIFRS	MIFRS	MIFRS
Date of Transition to IFRS		January 1, 2011	January 1, 2012	January 1, 2013	January 1, 2014

H - historic year regulatory financial information
B - bridge year regulatory financial informaiton
T - test year regulatory financial information
(green box) Year in which both CGAAP and MIFRS information required

MIFRS Application Filing for the Rate Year

- Summary of Impacts to Revenue Requirement from Transition to MIFRS - Appendix 2-Y
  - For modified IFRS applications, the applicants must provide a summary of the dollar impacts of modified IFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the overall impact on the proposed revenue requirement.
  - Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting.

Summary of Impacts to Revenue Requirement from Transition to MIFRS: Appendix 2-Y

Appendix 2-YA

MIFRS Application Filing for the 2014 Rate Year

- 2.3.2 Accounting Standards
  - Provide a summary of changes to its accounting policies made since the applicant’s last cost of service filing (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.).
  - Revenue requirement impacts of any changes in accounting policies must be separately quantified.

Rate Base: Gross Assets – Property, Plant, and Equipment (PP&E) and Accumulated Depreciation

The Applicant Adopts IFRS in **2012** for Financial Reporting Appendix 2-B	
Property, Plant and Equipment	• Establish the continuity of historic cost by using the December 31, 2010 regulatory gross assets of property, plant and equipment as the opening January 1, 2011 regulatory gross assets. – December 31, 2010 regulatory gross PPE by asset class. – January 1, 2011 regulatory gross PPE by asset class.
Accumulated Depreciation	• Establish the continuity of historic cost by using the December 31, 2010 regulatory accumulated depreciation as the opening January 1, 2011 accumulated depreciation. – December 31, 2010 regulatory accumulated depreciation by asset class. – January 1, 2011 regulatory accumulated depreciation by asset class.

Rate Base: Gross Assets – Property, Plant, and Equipment (PP&E) and Accumulated Depreciation

The Applicant Adopts IFRS in **2013** for Financial Reporting Appendix 2-B	
Property, Plant and Equipment	• Establish the continuity of historic cost by using the December 31, 2011 regulatory gross assets of property, plant and equipment as the opening January 1, 2012 regulatory gross assets. – December 31, 2011 regulatory gross PPE by asset class. – January 1, 2012 regulatory gross PPE by asset class.
Accumulated Depreciation	• Establish the continuity of historic cost by using the December 31, 2011 regulatory accumulated depreciation as the opening January 1, 2012 accumulated depreciation. – December 31, 2011 regulatory accumulated depreciation by asset class. – January 1, 2012 regulatory accumulated depreciation by asset class.

Rate Base: Gross Assets – Property, Plant, and Equipment (PP&E) and Accumulated Depreciation

The Applicant Adopts IFRS in **2014** for Financial Reporting Appendix 2-B	
Property, Plant and Equipment	• Establish the continuity of historic cost by using the December 31, 2012 regulatory gross assets of property, plant and equipment as the opening January 1, 2013 regulatory gross assets. – December 31, 2012 regulatory gross PPE by asset class. – January 1, 2013 regulatory gross PPE by asset class.
Accumulated Depreciation	• Establish the continuity of historic cost by using the December 31, 2012 regulatory accumulated depreciation as the opening January 1, 2013 accumulated depreciation. – December 31, 2012 regulatory accumulated depreciation by asset class. – January 1, 2013 regulatory accumulated depreciation by asset class.

Rate Base: Gross Assets – Property, Plant, and Equipment (PP&E) and Accumulated Depreciation

The Applicant Adopts IFRS in **2015** for Financial Reporting Appendix 2-B	
Property, Plant and Equipment	• Establish the continuity of historic cost by using the December 31, 2013 regulatory gross assets of property, plant and equipment as the opening January 1, 2014 regulatory gross assets. – December 31, 2013 regulatory gross PPE by asset class. – January 1, 2014 regulatory gross PPE by asset class.
Accumulated Depreciation	• Establish the continuity of historic cost by using the December 31, 2013 regulatory accumulated depreciation as the opening January 1, 2014 accumulated depreciation. – December 31, 2013 regulatory accumulated depreciation by asset class. – January 1, 2014 regulatory accumulated depreciation by asset class.

Rate Base: Gross Assets – Property, Plant, and Equipment (PP&E)

Appendix 2-BA:
Fixed Asset Continuity Schedule

Key Note:

- Continuity statements should be reconcilable to the calculated depreciation expenses (Appendix 2-C) and presented by asset account.

Capital Expenditures – Capitalization Policy

2.5.2.3 Capitalization Policy

- File capitalization policy, including changes to that policy since the last rebasing application
- Must explain the reason for capitalization policy changes and whether they are as a result of adhering to an accounting requirement. The changes must be identified, (e.g. capitalization of indirect costs, etc.) and the causes of the changes must also be identified.

Capital Expenditures – Capitalization Policy

2.5.2.3 Capitalization Policy

- Per the Board's letter of July 17, 2012, must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory in 2013 for all distributors that have not yet made these changes and therefore all applications for 2014 rates should reflect that these changes were made in 2013 (the bridge year).
- These accounting changes must be implemented consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the Revised 2012 APH.

Capital Expenditures – Capitalization of Overhead

2.5.2.4 Capitalization of Overhead

- Must complete Appendix 2-D regarding overhead costs on self-constructed assets.
- Must identify the burden rates related to the capitalization of costs of self-constructed assets.
- Must identify the burden rates prior to and after the change, if the burden rates were changed since the last rebasing application.

Appendix 2-DA: Overhead Expense

2.7.4 Depreciation, Amortization and Depletion

- Use the Board sponsored Kinectrics study or provide your own study to justify changes in useful lives.
- Must provide a list detailing all asset service lives and tie this list to the Uniform System of Accounts as appropriate.
  - Must detail differences of its asset service lives from the Typical Useful Lives (“TUL”) from the Kinectrics Report and provide a detailed explanation for using a service life that is different from the TUL in the Kinectrics Report.
  - Must perform a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes.

Depreciation/Amortization/Depletion

IFRS for financial reporting in 2012

Appendices 2-CA to 2-CE: Depreciation and Amortization Expense

Depreciation/Amortization/Depletion

IFRS for financial reporting in 2013

Appendices 2-CF to 2-CI: Depreciation and Amortization Expense

Depreciation/Amortization/Depletion

IFRS for financial reporting in 2014

Appendices 2-CJ to 2-CM: Depreciation and Amortization Expense

Common Pitfalls from Prior Years' MIFRS Applications

- Some CGAAP or MIFRS schedules for depreciation and PP&E were either missing or incomplete.
- It was not clear whether the schedules were MIFRS schedules or CGAAP schedules.
- Some applicants provided schedules for depreciation and PP&E that were not labelled properly.
- The closing of one year in the PP&E schedule was not equal to the opening balance in the next year.

Common Pitfalls from Prior Years' MIFRS Applications

- The fixed asset balances used in the rate base calculation did not agree to the figures shown on the fixed asset continuity schedule and no explanation or reconciliation was provided.
- Some applicants did not provide the transition year in both CGAAP and MIFRS, but rather went straight from CGAAP in bridge year to MIFRS in test year in the continuity schedules.
  - The rate base and the revenue requirement were adversely impacted.

Common Pitfalls from Prior Years' MIFRS Applications

- Some applicants did not file a copy of their capitalization policies in the pre-filed evidence.
- In the response to an interrogatory, some applicants stated that they did not have a capitalization policy – this is a contradiction of Section 2.5.2.3 of the Filing Requirements.

Common Pitfalls from Prior Years' MIFRS Applications

- Multiple updates of MIFRS evidence occurred without an explanation by some applicants during the course of rate proceeding. If possible, multiple updates should be avoided.
- The MIFRS evidence also changed from one filing to another without an explanation by some applicants.
- In some cases, there was insufficient or incomplete information filed to describe the net impact on the revenue requirement under MIFRS.

Questions

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Setting Rates on Canadian Generally Accepted Accounting Principles ("CGAAP")

Daria Babaie, Manager, Regulatory Audit and Accounting
Tina Li, Project Advisor, Regulatory Audit and Accounting
July 24, 2013

Agenda

1. Accounting Standards
2. CGAAP Application
3. 2014 Filing Requirements – CGAAP
   – CGAAP Appendices
4. Common Pitfalls from Prior Years' CGAAP Applications
5. Questions

2.3.2 Accounting Standards

- The applicant should specify the accounting standard that is used in preparation of its application filed for the 2014 rate year.

- If CGAAP has been used as the basis of the application, the applicant must clearly state this in its application.

2.3.2 Accounting Standards

Regardless of the accounting standard used in the application, the applicant must:

- Provide a summary of changes to its accounting policies made since the applicant's last cost of service filing.
  - e.g. capitalization of overhead, capitalization of interest, depreciation, etc.
- Revenue requirement impacts of any changes in accounting policies must be separately quantified.

2.3.2.2 CGAAP Application

- The option of filing a CGAAP application is available if the applicant chooses not to adopt IFRS for financial reporting purposes until January 1, 2015.

- Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP must implement regulatory accounting changes for depreciation expense and capitalization policies as at January 1, 2013.
  - These changes are mandatory in 2013 for all distributors that have not yet made these changes in 2012, and therefore all applications for 2014 rates should reflect that these changes were made in 2012 or 2013.

Appendix 2-YB CGAAP Summary Impacts

Summary of Impacts to Revenue Requirement For Accounting Changes under CGAAP or ASPE

Appendix 2-YB

Appendix 2-YB

Closing NBV for 2013 and 2014 must agree to Appendix 2-BA Fixed Assets Continuity Schedule

Appendix 2-YB
Summary of Impacts to Revenue Requirement from Accounting Changes under CGAAP or ASPE

Ensure that impacts to each component of revenue requirement are filled and reasons are provided for the differences.

Revenue Requirement Component	2014 CGAAP or ASPE with the changes to the policies	2014 CGAAP without the changes to the policies	Difference	Reasons why the revenue requirement component is different under CGAAP or ASPE with the changes to the policies versus CGAAP without the changes to the policies
Closing NBV 2013	$ 65,000,000	$ 66,000,000	-$ 1,000,000	
Closing NBV 2014	$ 68,000,000	$ 70,500,000	-$ 2,500,000	
Average NBV	$ 66,500,000	$ 68,250,000	-$ 1,750,000	Difference is due to the change of the capitalization policy and depreciation policy in 2012.
Working Capital	$ 1,300,000	$ 1,250,000	$ 50,000	Difference is due to the difference in OM&A expense as outlined below
Rate Base	$ 67,800,000	$ 69,500,000	-$ 1,700,000	
Return on Rate Base	$ 4,407,000	$ 4,517,500	-$ 110,500	Return on Rate Base is calculated as Rate Base X 6.5% (WACC). The difference in return on rate base is due to the differnce of rate base as noted above.
			$ -	
OM&A	$ 13,500,000	$ 12,800,000	$ 700,000	Difference is due to the change of the capitalization policy in 2012.
Depreciation	$ 5,011,000	$ 5,505,000	-$ 494,000	Difference is due to the change of the depreciation policy in 2012
PILs or Income Taxes	$ 500,000	$ 685,000	-$ 185,000	Difference is due to the differences caused by accounting changes
			$ -	
Less: Revenue Offsets	-$ 1,080,000	-$ 1,080,000	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 22,338,000	$ 22,427,500	-$ 89,500	

Total Base Revenue Requirement must agree to the figure shown on RRWF

For CGAAP or ASPE applications, the applicants must provide a summary of the dollar impacts of CGAAP or ASPE to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from making capitalization and depreciation expense policy changes under CGAAP or ASPE.

2.5.1 Rate Base

Must provide a complete Appendix 2-BA1 for Fixed Assets Continuity Schedule for a CGAAP/USGAAP/ASPE Application.

Fixed Assets Continuity Schedule for CGAAP/USGAAP/ASPE

Appendix 2-BA1

2.5.2.3 Capitalization Policy

Must provide its capitalization policy, including changes to that policy since the last rebasing application filed with the Board.

- Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP or choosing to adopt ASPE must implement regulatory accounting changes for capitalization policies by January 1, 2013.
  - These changes are mandatory in 2013 for all distributors that have not yet made these changes and therefore all applications for 2014 rates should reflect that these changes were made in 2013 (the bridge year).
  - These accounting changes under CGAAP and ASPE must be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS (MIFRS) as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, and the Revised 2012 APH.

2.5.2.3 Capitalization Policy

- Must explain the reason for these changes and whether they are a result of adhering to an accounting requirement.

- The changes must be identified, (e.g. capitalization of indirect costs, etc.) and the causes of the changes must also be identified.

2.5.2.4 Capitalization of Overhead

- Must complete Appendix 2-DB regarding overhead costs on self-constructed assets.

- Must identify the burden rates related to the capitalization of costs of self-constructed assets.

- Must identify the burden rates prior to and after the change, if the burden rates were changed since the last rebasing application.

2.5.2.4 Capitalization of Overhead

Appendix 2-DB:
Overhead Expense

Appendix 2-DB: Overhead Expense

ABC Utility

Note: The figures presented in this worksheet are fictitious and are intended for presentation purposes only.

File Number:	EB-2014-1234
Exhibit:	
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Date:	

Appendix 2-DB
Overhead Expense

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under revised CGAAP or ASPE (with the changes in capitalization and depreciation expense policies).

Nature of the Overhead Costs	(A) [1] Dollar Impact on PP&E Historic Year	(B) Dollar Impact on PP&E Bridge Year	(C) Dollar Impact on PP&E Test Year	(D) Dollar Impact - PP&E Variance Test versus Bridge	(E) [1] Dollar Impact - PP&E Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits	$ 20,000	$ 22,000	$ 18,000	-$ 4,000	-$ 2,000	Y	Employee benefits incurred on direct labour used to construct plant
costs of site preparation	$ 50,000	$ 40,000	$ 70,000	$ 30,000	$ 20,000	Y	Costs incurred to get site prepared to construct plant
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		
administration and other general overhead costs				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 70,000	$ 62,000	$ 88,000	$ 26,000	$ 18,000		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under revised CGAAP or ASPE (with the changes in capitalization and depreciation expense policies) and are included in OM&A.

Nature of the Overhead Costs	(A) [1] Dollar Impact on OM&A Historic Year	(B) Dollar Impact on OM&A Bridge Year	(C) Dollar Impact on OM&A Test Year	(D) Dollar Impact - OM&A Variance Test versus Bridge	(E) [1] Dollar Impact - OM&A Variance Test versus Historic	(F) Directly Attributable? (Y/N)	(G) Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead
employee benefits				$ -	$ -		
costs of site preparation				$ -	$ -		
initial delivery and handling costs				$ -	$ -		
costs of testing whether the asset is functioning properly				$ -	$ -		
professional fees				$ -	$ -		
costs of opening a new facility				$ -	$ -		
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		
costs of conducting business in a new location or with a new class of customer (including costs of staff training)		$ 5,000	$ 2,000	-$ 3,000	$ 2,000	N	Staff training costs associated with expanding utility plant to a new location
administration and other general overhead costs	$ 50,000	$ 30,000	$ 45,000	$ 15,000	-$ 5,000	N	General overhead costs (e.g. executive management salary allocation not directly attributable to construction of new plant)
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 50,000	$ 35,000	$ 47,000	$ 12,000	-$ 3,000		

2.7.4 Depreciation, Amortization and Depletion

- Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP or choosing to adopt ASPE must implement regulatory accounting changes for depreciation expense policy by January 1, 2013.
  - These changes are mandatory in 2013 for all distributors that have not yet made these changes and therefore all applications for 2014 rates should reflect that these changes were made in 2013 (the bridge year).
  - These accounting changes under CGAAP and ASPE must be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS (MIFRS) as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report and the Revised 2012 APH.

2.7.4 Depreciation, Amortization and Depletion

- Use the Board sponsored Kinectrics study or provide own study to justify changes in useful lives.

- Must provide a list detailing all asset service lives and tie this list to the Uniform System of Accounts as appropriate.
  - Must detail differences of its asset service lives from the Typical Useful Lives ("TUL") from the Kinectrics Report and provide a detailed explanation for using a service life that is different from the TUL in the Kinectrics Report.
  - Must perform a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes.

2.7.4 Depreciation, Amortization and Depletion

- Must specify the details if it adopted, in part or in full, TUL estimates that were used in the Board-sponsored Kinectrics study or its own asset service life studies, and determine the impacts.

- Must provide a detailed justification for any changes in service lives.

2.7.4 Depreciation, Amortization and Depletion

The changes to capitalization and depreciation expense policies Effective Jan 1, 2012

Appendix 2-CN to 2-CQ: Depreciation and Amortization Expense

2.7.4 Depreciation, Amortization and Depletion

The changes to capitalization and depreciation expense policies Effective Jan 1, 2013

Appendix 2-CR to 2-CU: Depreciation and Amortization Expense

Common Pitfalls from Prior Years' CGAAP Applications

- There was confusion among some applicants regarding accounting standard used for the rate setting purposes vs. accounting standard used for the financial reporting purposes.
  - CGAAP vs. MIFRS
- It was not clear what basis of accounting standard some applicants used in preparation of their rate applications.
  - The applicant referred to the deferral of the IFRS implementation, but showed appendices under both CGAAP and MIFRS for both bridge year and the test year.
- Use of the term "Modified CGAAP" by some applicants for the application prepared under CGAAP. However, the term "Modified CGAAP" is not a defined term by the Board.

Common Pitfalls from Prior Years' CGAAP Applications

- Some applicants changed the accounting standard basis during the rate proceeding from MIFRS to CGAAP without updating all necessary evidence.

- The schedules for depreciation and PP&E were missing or incomplete and not consistent with basis of accounting standard used for the rate application.

- The fixed asset balances used in the rate base calculation did not agree to the figures shown on the fixed asset continuity schedule and no explanation or reconciliation was provided.

Common Pitfalls from Prior Years' CGAAP Applications

- The closing of one year in the PP&E schedule was not equal to the opening balance in the next year with no reconciliation provided.
  - Smart meter amounts caused the fixed assets closing balances to not agree to next year's opening balance with no reconciliation provided.

- Multiple updates of CGAAP evidence occurred without an explanation by some applicants during the course of rate proceeding. If possible, multiple updates should be avoided.

- The CGAAP evidence also changed from one filing to another without an explanation by some applicants.

Common Pitfalls from Prior Years' CGAAP Applications

- In some cases, there was insufficient or incomplete information filed to describe the net impact on the revenue requirement under CGAAP.
- Some applicants provided schedules for depreciation and PP&E that were not labelled properly.
- Some applicants did not file a copy of their capitalization policies in the pre-filed evidence.
- In the response to an interrogatory, some applicants stated that they did not have a capitalization policy.
  - This is a contradiction of Section 2.5.2.3 of the Filing Requirements.

Questions?

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Exhibit 9 - Deferral and Variance Accounts

Daria Babaie, Manager, Regulatory Audit and Accounting
Tina Li, Project Advisor, Regulatory Audit and Accounting
July 24, 2013

Agenda

1. 2014 Filing Requirements
   - ✓ Exhibit 9 - Deferral and Variance Accounts
     - DVAs Continuity Schedule and Relevant Appendices
   - ✓ Other relevant sections in Chapter 2 for DVAs
2. Accounting Order
3. Common Pitfalls from Prior Years' Rate Applications
4. Questions

Exhibit 9 - Deferral and Variance Accounts

Required information to be filed regardless of whether or not the applicant is seeking disposition of any or all DVAs:

1. List of all outstanding DVAs and a brief description of any account that the applicant may have used differently than as described in the APH.
2. Identification of which Group 2 accounts the distributor will continue and discontinue on a going-forward basis, with an explanation for each.

Exhibit 9 - Deferral and Variance Accounts

3. A continuity schedule for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances.

   ✓ Propose an allocator based on the cost driver(s), along with the charge type for recovery purposes, and include this in the continuity schedule if proposing to allocate a DVA for which the Board has not established an approved allocator.

Exhibit 9 - Deferral and Variance Accounts

4. Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account.

5. A statement as to whether or not any adjustments were made to DVA balances that were previously approved by the Board on a final basis in both cost of service and IRM proceedings.
   - ✓ If so, must provide explanations for the nature and amounts of the adjustments and include supporting documentation;

Exhibit 9 - Deferral and Variance Accounts

6. A breakdown of energy sales and cost of power expense balances, as reported in the Audited Financial Statements by distributors, mapped to USoA account number.
   - ✓ Must reconcile these numbers to the Audited Financial Statements.
   - ✓ Must explain why it is making a profit or loss on the commodity if there is a difference between the energy sales and cost of power expense reported numbers.
     - o The distributor should not make profit or loss on the commodity.
7. A statement confirming that the distributor pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions.
   - ✓ Must provide an explanation if this is not the case.

Example for Energy sales not agreeing to Cost of Power

Example for Energy sales not agreeing to Cost of Power				
Revenue USoAs related to RSVA		**All RSVAs**	**AFS**	
4006	Residential Energy Sales	$ (2,300,000)		
4010	Commercial Energy Sales	$ (1,500,000)		
4015	Industrial Energy Sales	$ (50,000)		
4020	Energy Sales to Large Users	$ (1,108,000)		
4025	Street Lighting Energy Sales	$ (30,000)		
4030	Sentinel Lighting Energy Sales	$ (10,592)		
4035	General Energy Sales	$ -		
4040	Other Energy Sales to Public Authorities	$ -		
4045	Energy Sales to Railroads and Railways	$ -		
4050	Revenue Adjustment	$ (141,819)		
4055	Energy Sales for Resale			
4062	Billed WMS	$ (430,739)		
4066	Billed NW	$ (349,382)		
4068	Billed CN	$ (76,211)		
4075	Billed - LV	$ (204,144)		
Sum of Energy Sales		**$ (6,200,886)**	**Energy sales**	**$ (6,200,886)**
Expense USoAs related to RSVA		**All RSVAs**		
4705	Power Purchased	2,800,000		
4707	Charges - Global Adjustment	2,200,000		
4708	Charges-WMS	433,519		
4710	Cost of Power Adjustments	0		
4714	Charges-NW	356,117		
4716	Charges-CN	82,388		
4730	Rural Rate Assistance Expense	0		
4750	Charges - LV	203,188		
Sum of Cost of Power		**6,075,211**	**Cost of Power**	**$ 6,075,211**
Difference (Potential Profit/Loss on Commodity)		**$ (125,675)**		**$ (125,675)**

Utility ABC made potential profit on the commodity for $125,675, which indicates inaccurate regulatory accounting for RSVAs.

Deferral and Variance Accounts – Explanation Threshold

For Each of the DVAs:

- Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's RRR filings.

Deferral and Variance Accounts – Explanation Threshold

- Provide explanations even if such variances are below the 5% threshold if the variances in question relate to:
  - ✓ Matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or,
  - ✓ The cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings.

Disposition of Deferral and Variance Accounts

- Identify all accounts for which it is seeking disposition and is not proposing disposition and provide the reasons.

- Propose rate riders and disposition period (default is one year). Provide an explanation if deviating from the default period.

- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period.

Disposition of Deferral and Variance Accounts

- Establish separate rate riders to recover the RSVA Power Account Global Adjustment from non-RPP customers.

- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances.

Exhibit 9 - Deferral and Variance Accounts

2014 EDDVAR Continuity Schedule

2.12.1 PILs and Tax Variances for 2006 and Subsequent Years - Account 1592

- If the distributor has not already filed for disposition in a prior rate year, the Board expects distributors to file for disposition of account 1592 in their cost of service applications.

- Distributors must complete and file Appendix 2-TA in support of their request to dispose the balance in account 1592.

2.12.1 PILs and Tax Variances for 2006 and Subsequent Years - Account 1592

Appendix 2-TA, Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

Appendix 2-TA, Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

ABC utility
The example is for illustration purpose only.

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Appendix 2-TA
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	**Principal as of December 31, 2012**
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	N/A
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	-$ 34,000
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	-$ 40,000
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	-$ 15,000
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	-$ 10,000
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	$ 7,000
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	$ 5,000
Capital Cost Allowance class changes from 2006 EDR application for 2011	
Capital Cost Allowance class changes from 2006 EDR application for 2012	
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
Insert description of additional item(s) and new rows if needed.	
Total	-$ 87,000

- Large Corporation Tax is not applicable to this utility

2.12.2 Harmonized Sales Tax Deferral Account, Account 1592, Sub-account HST/OVAT ITCs

- **What should be recorded in this sub-account of 1592?**
  - ✓ The incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

- **What is the time frame?**
  - ✓ Beginning July 1, 2010 to the end of Dec 31, 2013 or April 30, 2014 depending on the start of the rate year.

2.12.2 Harmonized Sales Tax Deferral Account - Account 1592, Sub-account HST/OVAT ITCs

- **What is the methodology of the analysis?**
  - ✓ Provide an analysis that supports the distributor’s conformity with December 2010 APH FAQs, in particular the example shown in FAQ #4.

- **Exceptions:**
  - ✓ Last CoS rate application already dealt with HST issue.

2.12.2 Harmonized Sales Tax Deferral Account - Account 1592, Sub-account HST/OVAT ITCs

Appendix 2-TB, Account 1592, Sub-account HST/OVAT ITCs

Appendix 2-TB, Account 1592, Sub-account HST/OVAT ITCs

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Tab:	
Schedule:	
Page:	
Date:	

ABC utility

The example is for illustration purpose only.

Appendix 2-TB
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries.

100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs), should be recorded in this table.

PST savings should be performed on both OM&A and Capital items

Summary of PST Savings from 2009 Historic Year Analysis

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal Jan-April 2014 [1]	Carrying Charges to April 30, 2014	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings	-$ 38,000	-$ 76,000	-$ 76,000	-$ 76,000	-$ 76,000	-$ 19,000	-$ 361,000
Capital Items PST Savings	-$ 5,000	-$ 10,000	-$ 10,000	-$ 10,000	-$ 10,000	-$ 2,500	-$ 47,500
Total Annual PST Savings [2]	-$ 43,000	-$ 86,000	-$ 86,000	-$ 86,000	-$ 86,000	-$ 21,500	-$ 408,500

100% of the savings should be recorded in the sub-account of 1592

[1] Include January to April 30, 2014 PST savings if the rate year begins May 1, 2014. If the rate year begins Jan 1, 2014, include PST savings to December 31, 2013.

[2] Derived PST savings proxy for each year per 2009 historic year analysis

PST saving analysis - use 2009 historical year analysis or actual expenditures

Note: Assumes level OM&A and Capital Spending year over year. An alternative detailed transactional analysis may also be performed using actual expenditures from 2010 to the start of the rate year.

2.12.3 One-time Incremental IFRS Costs

- Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance

  - ✓ As per the October 2009 APH FAQ #1 and FAQ #2,
    - An applicant must file a request for review and disposition of the balance in **its next cost of service rate application immediately after the IFRS transition period**.

2.12.3 One-time Incremental IFRS Costs

For an applicant who files under MIFRS must:

1. File for disposition of the balance in Account 1508, Other Regulatory Assets, Sub-account IFRS Transition Costs Variance reflecting the difference between the amounts recovered in rates and the actual incurred costs.

2. Provide a statement as to whether any one-time administrative incremental IFRS transition costs are embedded in the proposed 2014 revenue requirement.
   - ✓ If this is the case, the applicant must state the section of the proposed 2014 revenue requirement that includes these costs.

2.12.3 One-time Incremental IFRS Costs

3. Provide explanations for each category of costs recorded in the account and how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.
4. Provide explanations for material variances that may exist in the Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance account.
5. Provide a confirmation statement that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy changes are recorded in the account.
   - ✓ Must provide an explanation if this is not the case.

2.12.3 One-time Incremental IFRS Costs

- An applicant who files an application under CGAAP/ASPE/USGAAP standard:
  - ✓ This account does not need to be disposed until full conversion to IFRS is complete.

- Centre Wellington 2013 CoS Decision and Order EB-2012-0113 dated May 28, 2013 stated that:
  - ✓ "The Board will not dispose of this account at this time, either on a final or interim basis. The Board finds that it is more appropriate to consider this account in total after the transition to IFRS has been made."

2.12.3 One-time Incremental IFRS Costs

Appendix 2-U: One-Time Incremental IFRS Costs

2.12.3 One-time Incremental IFRS Costs

ABC utility

The example is for illustration purpose only.

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Fill this Appendix if the application is filed under MIFRS

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Actual Costs Incurred 2012	Audited Carrying Charges to Dec 31, 2012	Total Audited Actual Costs to Dec 31, 2012	RRR 2.1.7 Balance 31-Dec-12	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 20,000	$ 30,000	$ 35,000	$ 50,000		$ 135,000			
professional legal fees	$ 5,000	$ 6,000	$ 8,000	$ 2,000		$ 21,000			
salaries, wages and benefits of staff added to support the transition to IFRS		$ 10,000	$ 5,000			$ 15,000			
associated staff training and development costs		$ 8,000	$ 7,500	$ 6,000		$ 21,500			
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion						$ -			
						$ -			
						$ -			
						$ -			
						$ -			
Amounts, if any, included in previous Board approved rates (amounts should be negative) [3]		-$ 25,000	-$ 25,000	-$ 16,667		-$ 66,667			
						$ -			
Insert description of additional item(s) and new rows if needed.						$ -			
Total	$ 25,000	$ 29,000	$ 30,500	$ 41,333	$ 9,350	$ 125,833		$ 125,833	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 Applicants are to provide an explanation of material variances in evidence

3 If there were any amounts approved in previous Board approved rates, please state the EB #: EB-2010-1234

Ensure to include the amoutns approved by the Board and ther reference to the Board Decision.

Account 1575, IFRS-CGAAP Transitional PP&E Amounts & Account 1576, Accounting Changes Under CGAAP

	Purpose	Accounting basis for Application	Mechanics
Account 1575	To capture all PP&E accounting changes made on transition to IFRS, not just those related to capitalization and depreciation (e.g. customer contributions, asset retirement obligations, interest capitalization, etc.)	an applicant that files a 2014 cost of service application on the basis of MIFRS	- Rate of Return component applies. - Separate Rate Rider for disposition per the letter dated June 25, 2013
Account 1576	To record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under CGAAP or ASPE in 2012 or as mandated by the Board in 2013	an applicant that files a 2014 cost of service application on the basis of CGAAP or ASPE	Per the letter dated June 25, 2013: - Rate of Return component applies. - Separate Rate Rider for disposition

Disposition Period for Account 1575 and Account 1576

- The applicant must propose a disposition period of the account balances using a volumetric rate rider.
- Rate rider expiry dates will be set out in the rate orders to align with the approved disposition period.
- The Board's determination for disposition period will be on a case-by-case basis and that it be guided primarily by such considerations as bill impacts and the financial impact on distributors.

Account 1575, IFRS-CGAAP Transitional PP&E Amounts & Account 1576, Accounting Changes Under CGAAP

- Deferral Account 1575 and variance Account 1576 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account.

- The accounting changes applicable to Account 1576 are not applicable to Account 1575 in relation to "changeover date" accounting on the applicant's adoption of IFRS.
  - ✓ APH FAQs July 2012, Appendix B, Note 2

Section 2.12.4 Account 1575, IFRS-CGAAP Transitional PP&E Amounts

Key Notes:

1. The Fixed Asset Continuity Schedule (Appendix 2-BA) and the Depreciation Schedules (Appendix 2-CB to 2-CE or 2-CG to 2-CI or 2CL to CM) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount.

2. Provide a breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS.

Section 2.12.4 Account 1575, IFRS-CGAAP Transitional PP&E Amounts

Key Notes:

3. Provide the supporting analysis of the amounts in this account by completing Appendix 2-EA, 2-EB or 2-EC to the Filing Requirements.
   - ✓ The drivers of the change in closing net PP&E (CGAAP versus MIFRS) must be identified and quantified.

4. Provide a separate volumetric rate rider for Account 1575 for the clearance of the account balance.
   - ✓ Due to change in the Board policy, no adjustments should be made for return component in the revenue requirement work form (RRWF) and for an amortized amount of the account balance in depreciation and amortization expense schedule for the test year.

3. Propose a disposition period.

Section 2.12.4 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

IFRS for Financial Reporting in 2012

Appendix 2-EA: IFRS-CGAAP Transitional PP&E Amounts

IFRS for Financial Reporting in 2013

Appendix 2-EB: IFRS-CGAAP Transitional PP&E Amounts

Appendix 2-EB: IFRS-CGAAP Transitional PP&E Amounts

File Number	#REF!
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

ABC utility

The example is for illustration purpose only.

Appendix 2-EB
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
2013 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2013 for financial reporting purposes

Ensure that Openning PP&E agreed under CGAPP and under MIFRS

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2013.

PP&E opening, closing balances, net additions, net depreciations should all agree to Appendix 2-BA

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
			$	$	$	$	$	$	$
PP&E Values under CGAAP									
Opening net PP&E - Note 1			1,000,000	750,000					
Net Additions - Note 4			250,000	350,000					
Net Depreciation (amounts should be negative) - Note 4			-500,000	-650,000					
Closing net PP&E (1)			750,000	450,000					
PP&E Values under MIFRS (Starts from 2012, the transition year)									
Opening net PP&E - Note 1			1,000,000	850,000					
Net Additions - Note 4			150,000	200,000					
Net Depreciation (amounts should be negative) - Note 4			-300,000	-520,000					
Closing net PP&E (2)			850,000	530,000					
Difference in Closing net PP&E, CGAAP vs. MIFRS			-100,000	-80,000					

No Adjustments to RRWF and Deperciation schedule for these amounts

the correct WACC should be used and the finalized rate should be used once it is updated and agreed/approved.

Effect on Deferral and Variance Account Rate Riders

Closing balance in deferral account	-	80,000
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 2	-	26,000
Amount included in Deferral and Variance Account Rate Rider Calculation	-	106,000

WACC	6.50%
# of years of rate rider disposition period	5

Section 2.12.4 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

IFRS for Financial Reporting in 2014

Appendix 2-EC: IFRS-CGAAP Transitional PP&E Amounts

2.12.5 Account 1576, Accounting Changes Under CGAAP

- The accounting changes made in 2012 under CGAAP:
  - ✓ Make the changes to the accounting capitalization or depreciation expense policies effective January 1, 2012;
  - ✓ Incorporate the impact of these changes as at January 1, 2012 (effective starting the Historic year 2012).

- The accounting changes made in 2013 under CGAAP:
  - ✓ Make the changes to the accounting capitalization or depreciation expense policies effective January 1, 2013;
  - ✓ Incorporate the impact of these changes as at January 1, 2013 (effective starting the Bridge year 2013).

2.12.5 Account 1576, Accounting Changes Under CGAAP

Key Notes:

1. The Fixed Asset Continuity Schedule (Appendix 2-BA) and the Depreciation Schedule (Appendix 2-CA, 2-CF, 2-CJ, 2-CK) in the rate application must not be adjusted for balances related to the Account 1576, Accounting Changes Under CGAAP.

2. Provide a breakdown of the balance related to Account 1576.

2.12.5 Account 1576, Accounting Changes Under CGAAP

Key Notes:

1. Provide the supporting analysis of the amounts in this account by completing Appendices 2-ED or 2-EE.
   - ✓ The drivers of the change in closing net PP&E (former policies under CGAAP versus revised policies under CGAAP or ASPE) must be identified and quantified.

4. Provide a separate volumetric rate rider for Account 1576 for the clearance of the account balance.
   - ✓ Due to change in the Board policy, no adjustment should be made for an amortized amount of the account balance in depreciation and amortization expense schedule for the test year.

5. Propose a disposition period.

2.12.5 Account 1576, Accounting Changes Under CGAAP

Changes in Accounting Policies under CGAAP effective Jan 1, 2012

Appendix 2-ED:Accounting Changed Under CGAAP

Appendix 2-ED:Accounting Changed Under CGAAP

ABC utility
The example is for illustration purpose only.

File Number	#REF!
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-ED
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

PP&E opening, closing balances, net additions, net depreciations should all agree to Appendix 2-BA

Ensure that Openning PP&E agreed under former CGAPP and under revised CGAAP

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			1,000,000	750,000					
Net Additions - Note 4			250,000	350,000					
Net Depreciation (amounts should be negative) - Note 4			-500,000	-650,000					
Closing net PP&E (1)			750,000	450,000					
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1			1,000,000	850,000					
Net Additions - Note 4			150,000	200,000					
Net Depreciation (amounts should be negative) - Note 4			-300,000	-520,000					
Closing net PP&E (2)			850,000	530,000					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-100,000	-80,000					

No Adjustments to RRWF and Depreciation schedule for these amounts

the correct WACC should be used and the finalized rate should be used once it is updated and agreed/approved.

Effect on Deferral and Variance Account Rate Riders				
Closing balance in Account 1576	-	80,000	WACC	6.50%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	26,000	# of years of rate rider disposition period	
Amount included in Deferral and Variance Account Rate Rider Calculation	-	106,000		5

2.12.5 Account 1576, Accounting Changes Under CGAAP

Changes in Accounting Policies under CGAAP effective Jan 1, 2013

Appendix 2-EE: Accounting Changes Under CGAAP

Appendix 2-EE:Accounting Changed Under CGAAP

ABC utility	**File Number:**	0
The example is for illustration purpose only.	**Exhibit:**	
	Tab:	
	Schedule:	
	Page:	
	Date:	

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

PP&E opening, closing balances, net additions, net depreciations should all agree to Appendix 2-BA

Ensure that Openning PP&E agreed under former CGAPP and under revised CGAAP

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				1,000,000					
Net Additions - Note 4				250,000					
Net Depreciation (amounts should be negative) - Note 4				-500,000					
Closing net PP&E (1)				750,000					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				1,000,000					
Net Additions - Note 4				150,000					
Net Depreciation (amounts should be negative) - Note 4				-300,000					
Closing net PP&E (2)				850,000					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-100,000					

No Adjustments to RRWF and Deperciation schedule for these amounts

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1576	- 100,000	WACC	6.50%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 32,500	# of years of rate rider disposition period	5
Amount included in Deferral and Variance Account Rate Rider Calculation	- 132,500		

the correct WACC should be used and the finalized rate should be used once it is updated and agreed/approved.

Other Relevant Sections in Chapter 2 for DVAs - 2.3.1 Integrated Distribution Planning for Eligible Investments to Connect Qualifying Generation

Capital Expenditures in a consolidated capital plan

- No new deferral accounts for these types of expenditures will be established, nor will distributors be expected to continue the use of existing deferral accounts.
- Distributors filing cost of service applications in 2014 and subsequent years must include proposals for disposition of any existing balances in the deferral accounts.

Other Relevant Sections in Chapter 2 for DVAs - 2.5.2.6 Addition of ICM Assets to Rate Base

- Any distributor that has an approved ICM must file a schedule of the ICM capital asset amounts it proposes be incorporated into rate base.

- The applicant must also file the account balances recorded under a number of sub-accounts under Account 1508, Other Regulatory Assets.

- Provide a reconciliation between amounts recorded in these accounts and amounts used to propose what will be incorporated into rate base and explain any differences.

2.4.5 Administration

Accounting Order

Accounting Order

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

1. Causation
2. Materiality
3. Prudence

Accounting Order

- Upon a request, the applicant must propose a draft accounting order which must include:
  - ✓ Account name and USoA number
  - ✓ Purpose and operation of account
    - A description of the mechanics of the account
  - ✓ Future Disposition
    - Proposed disposition of the account at the appropriate time, e.g., next cost of service application
  - ✓ Treatment of carrying charges
  - ✓ Sample journal entries
    - Proposed general ledger entries

Accounting Order

- Existing accounting order and list of any departures from the Uniform System of Accounts including references to accounting order.

- All requests by the applicant to approve accounting orders (deferral or variance accounts) must be separately identified in Section 2.4.5 Administration and clearly documented in the appropriate section of the application.

Example - 2013 CoS ABC UTILITY - Accounting Order

- **Account name and USoA number:**
  - ✓ 1508 Other Regulatory Assets, Sub-account OPEB Deferral Account
- **Purpose and operation of account:**
  - ✓ The account shall record the cumulative actuarial gains or losses in ABC's post-retirement benefits.
  - ✓ The deferral account shall be adjusted, subject to materiality, to record changes in the actuarial gains or losses in ABC's post- retirement benefits as supported by the annual updated actuarial valuation prepared for ABC. This actuarial valuation is received by ABC at the end of each year.
  - ✓ ABC will not record any actuarial gains or losses related to OPEB, incurred prior to 2013.
  - ✓ The deferral account is established in the absence of Board policy on the OPEB issue and will continue until the earlier of:
    - o A decision by the Board to implement a policy in respect to the OPEB which differs from the approach approved here, and
    - o ABC's next rebasing application.
- **Future disposition:**
  - ✓ The balances in this account, supported by appropriate documentation, will be reviewed by the Board for prudence and future disposition, subject to materiality, at ABC's next cost of service application.
- **Carrying charges:**
  - ✓ No carrying charges shall be recorded on this account.
- **Sample journal entries**

Common Pitfalls from Prior Years' Rate Applications

- Inconsistent figures among balances provided in the DVA continuity schedule
  - ✓ Principal and interest balances at the end of the year did not agree to the RRR filing;
  - ✓ Principal and interest balances at the end of the year did not agree to the balances in Audited Financial Statements.
- The figures provided in the columns for Board Approved Disposition amounts did not agree to the amounts approved in the prior years' Board Decisions and Orders.

Common Pitfalls from Prior Years' Rate Applications

- Inconsistent evidence/responses were provided during the interrogatory stage.

- Multiple updates of the DVA continuity schedule occurred without an explanation by some applicants during the course of rate proceeding. If possible, multiple updates should be avoided.

Common Pitfalls from Prior Years' Rate Applications

- Account 1592 Sub-account HST/OVAT ITCs
  - ✓ Some applicants requested for the deferral of the disposition of the account balance to the next CoS rate application.
  - ✓ The account was not accounted for in accordance with the APH and FAQs.
  - ✓ Some applicants reported zero balance in the DVA continuity schedule.

Common Pitfalls from Prior Years' Rate Applications

- Account 1575:
  - ✓ Used Account 1575 while Account 1576 should have been used.
  - ✓ Incorrect WACC rate was used to calculate the return component.

- Inconsistent disposition period was proposed for the deferral and variance accounts in various sections of the rate application.

Questions?

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Income Taxes or Payments In Lieu of Taxes (PILs)

Fiona O'Connell, Project Advisor, Regulatory Audit & Accounting
July 24, 2013

Agenda

1. Calculation of Income Tax / PILs Provision
2. 2014 Filing Requirements
   - What must be filed?
   - What adjustments are required to the PILs model for non-recoverable and disallowed expenses?
   - What integrity checks need to be completed?
3. Common Pitfalls from Prior Years' Rate Applications
4. Questions

Calculation of Income Tax / PILs Provision

Regulatory Income or Return on Equity (= ROE% X 40% X Rate Base)
Add: Book to Tax Adjustments (e.g. add back Depreciation, deduct CCA)
= Net Income for Tax Purposes
Less: Loss Carry-forwards
= Regulatory Taxable Income
X Tax Rate
= Total Income Taxes
Less: Tax Credits
= Income Tax / PILs Provision
Add: Gross-up
= <u>Income Tax / PILs Provision (Grossed-Up)</u> to be included in revenue requirement

2014 Filing Requirements – What Must be Filed?

- Detailed calculations of Income Tax or PILs requested for recovery in rates, including the live MS Excel version of the PILs model available on the Board's website.
- Supporting schedules and calculations identifying reconciling items.
  - e.g. Supporting schedules, calculations and explanations for "other additions" and "other deductions" in the applicant's PILs model.

2014 Filing Requirements – What Must be Filed?

- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, must be separated).
- Financial statements included with tax returns, if different from the financial statements filed in support of the application.

2014 Filing Requirements – What Must be Filed?

- Derivations of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years.
- A calculation of tax credits.
  - e.g., Apprenticeship Training Tax Credits, education tax credits.
  - A Scientific Research and Experimental Development ("SRED") return, if filed, may have confidential personal information of the people who are apprenticing like SIN, address, hourly rate, etc. which must be excluded from the filing.

2014 Filing Requirements – What Must be Filed?

- Regulatory assets (and regulatory liabilities) must generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.

2014 Filing Requirements – What Adjustments are Required to the PILs Model for Non-recoverable and Disallowed Expenses?

The following amounts must be excluded from the regulatory tax calculation in the PILs model, including the updated calculation filed as part of the draft Rate Order:

- Distribution-only expenses incurred by a distributor that may be deductible for general tax purposes, but for which recovery in 2014 distribution rates is partially or fully disallowed by the Board.
    - e.g. certain charitable donations

2014 Filing Requirements – What Integrity Checks need to be completed?

The following integrity checks must be completed and a statement provided to this effect, or an explanation if this is not the case.

- The depreciation and amortization added back in the PILs model must agree with the numbers disclosed in the deprecation section of the application (Appendix 2-C).
- The capital additions and deductions in the UCC/ CCA Schedule 8 must agree with the rate base section for historic, bridge and test years (Appendix 2-B).

2014 Filing Requirements - What Integrity Checks need to be completed?

- Schedule 8 of the most recent federal T2 tax return filed with the application must have a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st.
  - If the amounts do not agree, then the applicant must provide a reconciliation with explanations for the reasons.
- The CCA deductions in the application's PILs tax model for historic, bridge and test years must agree with the numbers in the UCC schedules for the same years filed in the application.

2014 Filing Requirements – What Integrity Checks need to be completed?

- Loss carry-forwards, if any, from the tax returns (Schedule 4) must agree with those disclosed in the application.
- CCA must be maximized even if there are tax loss carry-forwards.
- A statement must be included in the application as to when the losses, if any, will be fully utilized.

2014 Filing Requirements – What Integrity Checks need to be completed?

- OPEB and pension amounts
  - Amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation.
  - Amounts deducted must be reasonable when compared with the notes in the audited financial statements, Financial Services Commission of Ontario (“FSCO”) reports, and the actuarial valuations.
- The income tax rate used to calculate the tax expense must be consistent with the utility’s actual tax facts and evidence filed in the proceeding.

Common Pitfalls from Prior Years' Rate Applications

- When certain items included in the revenue requirement were changed in a response to an interrogatory, the impact of these changes was not reflected in an updated PILs provision.
  - The PILs provision was erroneously left unchanged.
  - An updated PILs model was not filed with interrogatory responses.
- No statement was filed by the applicant that the integrity checks had been completed.
- Supporting schedules, calculations and explanations for "other additions" and "other deductions" in the applicant's PILs model were not filed with the application.

Common Pitfalls from Prior Years' Rate Applications

- Capital assets were categorized in an incorrect CCA class in the UCC schedule.
  - e.g. Computer Hardware classified as Class 10 instead of Class 50
- The applicant had employees that qualified for the Ontario apprenticeship tax credit, the Ontario co-operative education tax credit, and the federal job creation tax credit. In some instances, these credits were not claimed by the applicant and the PILs provision may have been overstated.

Common Pitfalls from Prior Years' Rate Applications

- The depreciation and amortization expense added back in the PILs model did not agree with the numbers disclosed in the rate base section of the application.
- The capital additions and deductions in the UCC/ CCA Schedule 8 did not agree with the rate base section for historic, bridge and test years.
- Regulatory assets were included in the PILs calculations.

Questions?

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Exhibit 3 – Operating Revenue

Keith Ritchie, Project Advisor, Applications
July 24, 2013

Significance of Load Forecasting in Cost of Service Applications

- Establish the level of demand for the test period
- Operating and capital costs are largely driven by three demand drivers:
  - Number of customers
  - Consumption of customers (kWh)
  - (Peak) Demand of customers (kW)
- These drivers differ by classes of customers (Residential, GS < 50 kW, etc.)
- Used as allocators for recovery of costs from different customer classes
- Also used as the billing determinants for determining fixed and variable rates and for other rate riders
- Demand (customers, kWh, kW) factors into revenue sufficiency/deficiency

Forecasting Number of Customers

- Utilities have historical data on number of customers / connections by class

- Historical trends and levels generally an adequate basis for forecasting future growth
  - e.g. average annual growth rate, by customer class
  - Most utilities (and the communities they serve) have stable growth rates of about 0% to 2% per annum

- Adjustments may be used for unique growth patterns in individual classes, movement between customer classes, or changes in customer class definitions
  - Generally done for classes with smaller customer numbers and specific load profiles and demand (e.g. Large Use, Intermediate, Sentinel Lighting)

Forecasting Number of Customers (Example)

Number of Customers (or Connections) per Class - Average Annual

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service 1000 to 4999 kW	Large Use >5000 kW	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Total
2003	38,064	3,249	461	37	4	10,876	30	588	53,308
2004	39,401	3,324	488	38	4	11,253	29	602	55,138
2005	40,692	3,422	498	39	4	11,838	31	595	57,119
2006	41,643	3,468	510	40	4	12,237	31	581	58,513
2007	42,728	3,534	521	41	4	12,574	29	579	60,010
2008	43,747	3,581	539	41	4	12,781	28	580	61,301
2009	44,584	3,624	538	41	4	12,860	28	582	62,260
2010	45,477	3,661	543	42	4	12,948	27	584	63,285
2011	46,647.3	3,723.7	556.0	42.8	4.0	13,274.0	26.2	583.4	64,857.4
2012	47,848.1	3,787.8	569.2	43.6	4.0	13,608.8	25.8	582.8	66,470.2

Growth Rate in Numbers of Customers (Connections)

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service 1000 to 4999 kW	Large Use >5000 kW	Streetlights	Sentinel Lights	Unmetered Scattered Loads	Total
2003									
2004	1.0351	1.0231	1.0582	1.0317	1.0000	1.0347	0.9916	1.0235	1.0343
2005	1.0328	1.0295	1.0202	1.0175	1.0000	1.0520	1.0538	0.9895	1.0359
2006	1.0234	1.0136	1.0244	1.0345	1.0000	1.0337	0.9866	0.9759	1.0244
2007	1.0261	1.0189	1.0216	1.0208	1.0000	1.0275	0.9482	0.9974	1.0256
2008	1.0238	1.0133	1.0350	1.0020	1.0000	1.0165	0.9598	1.0014	1.0215
2009	1.0191	1.0120	0.9971	1.0020	1.0000	1.0062	1.0090	1.0036	1.0156
2010	1.0200	1.0102	1.0105	1.0244	1.0000	1.0068	0.9466	1.0029	1.0165
Geometric Mean	1.0257	1.0172	1.0237	1.0189	1.0000	1.0252	0.9844	0.9991	1.0248

Forecasting Demand and Consumption - Approaches

- Normalized Annualized Consumption (NAC)
- Multivariate Regression (system purchased kWh)
- Multivariate Regression (by customer classes)
- Combination of these approaches seen in 2013 cost of service applications
- Other approaches?

Forecasting Demand and Consumption

- Utilities generally forecast purchased consumption (kWh)
  - Purchases available monthly from IESO bills; customer billed demand often does not correspond to calendar months due to a utility's billing cycles
  - TOU data allows for measurement of consumption by calendar month, but will need several years for sufficient data.

- 2013 CoS: Several utilities used class-specific models for: Residential, GS < 50 kW, GS > 50 kW
  - Other classes forecasted through NAC
  - Source/construction of monthly billed kWh data before TOU data available?

Forecasting Demand and Consumption (cont'd)

- Purchased kWh converted to billed kWh through loss factor
  - Purchased kWh = Billed kWh / (1 + loss factor)
- Estimated purchased kWh then allocated to customer classes based on historical patterns
- Weather sensitivity applied to certain classes (typically Residential and GS < 50 kW)
- For Demand billed customers, purchased kW derived from estimated purchased kWh by class conversion factor

Forecasting Demand - NAC

- For each class, the weather normalized kWh for recent history is divided by the number of customers to get an average normalized consumption
    - Some classes (i.e. USL, streetlighting) not weather sensitive
- Test year weather normalized kWh = NAC X average customer/connections in test year (by class)
- For demand-billed classes, kW/kWh conversion based on historical statistics
- Specific adjustments to forecasts used in some circumstances
    - However, the NAC forecast was not generally adjusted to accommodate changes in economic conditions or conservation

Forecasting Demand - NAC

2004 Weather Normalized kWH

Class	Weather Actual kWh	Loss Factor	Weather Actual Retail kWh	Number of Customers (Connections)	Retail NAC
Residential	537,565,246	1.0463	513,777,354	57,473	8,939.46
GS < 50 kW	196,080,994	1.0463	187,404,180	5,227	35,853.11
GS > 50 kW	745,238,105	1.0463	712,260,446	744	957,339.31
Unmetered Scattered Load	3,302,257	1.0463	3,156,128	529	5,966.22
Streetlighting	10,527,524	1.0463	10,061,669	13,252	759.26

Load Forecast

Class		Conversion Factor kWh => kW	2006 Actual Normalized		2007 Bridge Normalized	2008 Test Normalized
Residential	Number of Customers		60659		61684	62984
	kWh		542,258,461.29		551,421,403.69	563,042,696.48
GS < 50 kW	Number of Customers		5320		5441	5476
	kWh		190,738,519.22		195,076,744.94	196,331,603.62
GS > 50 kW	Number of Customers		784		802	807
	kWh		750,554,018.72		767,786,126.29	772,572,822.84
	kW	0.00253	1,898,901.67		1,942,498.90	1,954,609.24
Large Use	Number of Customers		0		0	1
	kWh					14600000
	kW					30000
USL	Number of Connections		760		777	782
	kWh		4,534,324.16		4,635,749.83	4,665,580.91
Streetlighting	Number of Connections		14174		14414	14718
	kWh		10,761,703.34		10,943,924.93	11,174,738.94
	kW	0.00286	30,778.47		31,299.63	31,959.75

Source: ***EB-2007-0746***

Forecasting Demand – Multivariate Regression

- Demand = f(P, N, I, Weather, Seasonality, CDM, etc.)

Variable	**Description**	**Coefficient Sign**
P	Price	-ve
N	Number of customers/connections or size of community	+ve
I	Income or Economic Variable	+ve
Weather		
HDD	Heating Degree Days	+ve
CDD	Cooling Degree Days	+ve
Seasonality		
Days in Month	Number of Days in month; business days; peak period hours	+ve
Spring/Fall Flag	Binary Flag for spring and fall months to capture saddle period of energy consumption May overlap CDD/HDD or may capture other features of spring and fall saddle periods	-ve?
CDM	Variable to capture cumulative or persistent impacts of CDM programs	-ve
Other Variables		
August 2003 Blackout	Binary flag for blackout (Southern Ontario LDCs)	-ve

Regression Output - Example

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.979498096
R Square	**0.959416519**
Adjusted R Square	**0.957640992**
Standard Error	2599144.111
Observations	168

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	2.55528E+16	3.6504E+15	540.3558299	7.6408E-108
Residual	160	1.08089E+15	6.75555E+12		
Total	167	2.66337E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-90392763.89	8420661.724	-10.73463902	1.37481E-20	-107022741.6	-73762786.21	-107022741.6	-73762786.21
Heating Degree Days	28385.21457	1222.256206	23.22362073	4.06933E-53	25971.37893	30799.05022	25971.37893	30799.05022
Cooling Degree Days	180663.8591	12686.48852	14.24065129	3.01994E-30	155609.2936	205718.4246	155609.2936	205718.4246
Ontario Real GDP Monthly %	178921.2574	63156.91427	2.832963888	0.005205712	54192.57116	303649.9437	54192.57116	303649.9437
Number of Days in Month	1999057.103	265489.4682	7.52970397	3.50381E-12	1474741.548	2523372.658	1474741.548	2523372.658
Spring Fall Flag	-2056228.894	532917.4883	-3.858437636	0.000165158	-3108688.454	-1003769.334	-3108688.454	-1003769.334
Number of Customers	1840.232909	213.4496505	8.621391064	6.11717E-15	1418.690869	2261.774949	1418.690869	2261.774949
Number of Peak Hours	57334.26505	13188.35313	4.347340754	2.4426E-05	31288.56635	83379.96374	31288.56635	83379.96374

Source: Waterloo North Hydro, 2011 EDR (CoS) [EB-2009-0144]

- High R^2
- Significant Regression
- All variables have coefficients with correct signs and are statistically significant at 95% c.i.

Regression Output – Analysis

- t-statistics of variables significant
  - ~ 1.96 for two-tailed test @ 95% c.i.
  - ~ 1.65 for one-tailed test @ 95% c.i.
- Variables have coefficients of appropriate signs?
- F-statistic
  - Overall significance of fit of the model
- R^2 and Adjusted R^2
- Analysis of Forecasts and Residuals
  - Residuals and Mean Absolute Percentage Error (MAPE) should be evaluated based on periodicity of model (e.g. monthly)
  - Patterns in residuals?
    - May be indicative of omitted variables

Regression Analysis – Issues

- Do variables relate to or seem reasonable for LDC's service area?
  - Economic activity or market size
  - Meteorological data (HDD, CDD)
- What other variables were tried, and why were they rejected?
  - Proxies for economic activity or market size
  - CDM variable?
- Multicollinearity
- Do methodologies for constructed variables seem reasonable?
  - For class-specific billed kWh, how is the variable constructed to match billed kWh to calendar months?
  - TOU data from smart meters and interval meters will reduce this concern over time

Conservation and Demand Management – Issues for Load Forecasting

- “Persistence” of CDM programmes into future periods
- Variables to reflect CDM impacts (initial impacts and persistence)?
  - Trend variables
  - Estimates of CDM savings from OPA
- Utility should account for impacts of CDM programmes in all years up to the test year
  - Issue of the accuracy of bridge and test year forecasts, trending from historical actuals and/or reflecting CDM initiatives to meet licence conditions

CDM – Accounting for CDM Licence Conditions (2011 to 2014 Cost of Service Applications)

- Beginning in 2011, CDM reduction targets of consumption/demand a condition of a distributor's licence
  - 4-year targets defined for each distributor for 2011-2014 period, expressed in kWh and kW reductions
  - The kWh reductions are cumulative over the four-year period
- Standard practice in 2011 and 2012 CoS applications was to phase in the reductions @ an incremental 10% per year
  - 2011 = 10% of overall target
  - 2012 = 20% of overall target
  - 2013 = 30% of overall target
  - 2014 = 40% of overall target
- Beginning in 2013 CoS applications, CDM adjustments take into account OPA-reported impacts of 2011 (and 2012 for 2014 applications) CDM programs
- Calculated as an explicit adjustment on the base forecasted consumption/demand (from regression or NAC approaches)

LRAMVA (2011-2014 CDM programs)

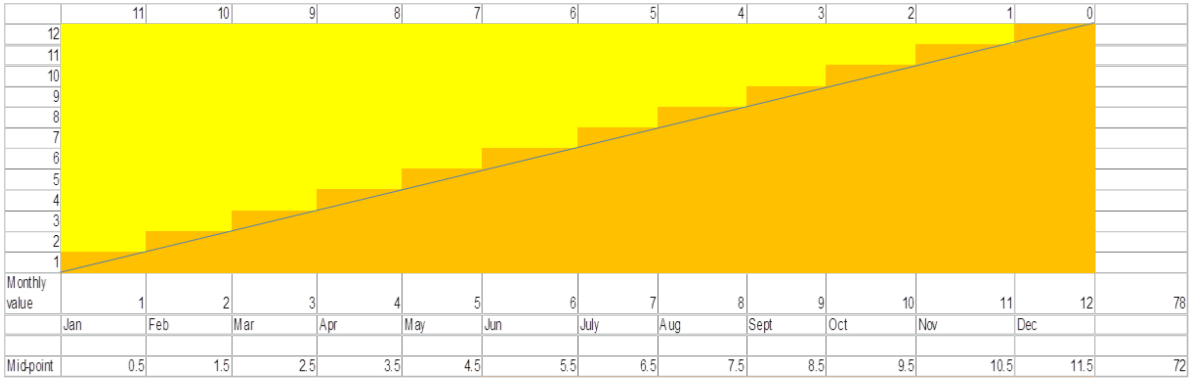
- LRAMVA
  - New CDM Guidelines issued April 2012
  - Relate to 2011-2014 CDM targets that are a condition of a distributor’s licence
  - Threshold for LRAMVA in test year will be the CDM adjustment that is factored into the load forecast in the cost of service test year
- CDM impacts measured by OPA or a third party in accordance with OPA guidelines
- For 2014, the Board must approve:
  - 2014 test year load forecast, including the persistence of historical 2011 and 2012 CDM programs, and expected 2013 and 2014 CDM programs impacts on the 2014 test year load forecast; and
  - Corresponding amounts used for establishing the 2014 LRAMVA threshold by class

2013 and 2014 LRAMVA (Concepts and Definitions)

- “Net” versus “Gross”
  - “Net” CDM – savings from customers taking advantage of OPA-recognized programs
  - “Gross” CDM – all CDM, including “free drivers”, “free riders”, spillover
- “Annualized” OPA results
  - OPA results are reported on an annualized basis – assuming all CDM, including new CDM, in effect for full year (January 1 to December 31)
  - Annualized results overstate “actual” impact in first year of program, due to timing and uptake of new CDM programs
- 2011 and 2012 CDM program impacts are reflected in actual 2011 and 2012 consumption
  - and thus influence, in some manner, base load forecasts from regression or NAC approaches

2013 CDM Variable

- Is there a CDM variable in the regression equation?
  - If yes, how is it constructed?
    - Segmented linear interpolation to construct monthly series
    - Does not reflect seasonality/cyclicality of CDM savings



    - What is the estimated coefficient? Is it reasonable?
      - ➢ Often seeing CDM coefficients much larger (-6 to -8) – more than just “gross-up” for free drivers/free riders (and losses)
  - If no, how has historical CDM been accounted for?
    - Assumed to be implicit in the historical data and reflected in the base forecast before the CDM adjustment

LRAMVA and CDM Adjustment

- The amount to be used for the LRAMVA and the CDM adjustment are different, but related, amounts
- LRAMVA is based on net and annualized OPA reported numbers for persistence of CDM programs from 2011 to test year on the test year load forecast
- CDM adjustment on load forecast must recognize the following:
  - "real" 2014 CDM impact on 2014 demand is less than annualized (½ year rule used as default)
  - 2011 and 2012 CDM program impacts are captured, in some form, in 2011 and 2012 actuals
  - CDM adjustment is the additional impact beyond what is in the base forecast and reflecting that first year CDM program impacts are <u>not</u> full annualized impact as reported by the OPA

Board Policy and Practice

- Centre Wellington Hydro Ltd. (EB-2012-0113) – May 28, 2013
  - Accepts LRAMVA basis of cumulative “net” annualized OPA results
  - Historical CDM impacts in historical actuals and thus in base forecast from regression/NAC method
  - Half-year rule for 2013 CDM program on 2013 test year forecast
  - Full-year persistence of 2012 CDM on 2013 test year forecast
- Settlement Agreements before and after largely consistent with this

Appendix 2-I (Load Forecast CDM Adjustment Work Form)

- Spreadsheet used in interrogatories in 2013 CoS applications to use results to data and to derive the related amounts for the LRAMVA and the CDM adjustment
- Updated for 2014 Cost of Service applications
  - Flexibility to address possible issues
    - 2012 CDM programs only have half-year impact on 2012 actuals, but need annualized persistence in 2014 test year
    - Adjustment for system losses if base forecast derived from system-purchased kWh

OPA 2011 Final Results Report – August 31, 2012

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.53	0.53	0.53	0.48
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.48
nder Bay Hydro Electricity Distribution Inc. 2014 Annual CDM Capacity Target:				8.48
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				5.63%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.16	2.16	2.16	2.03	8.50
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					8.50
Thunder Bay Hydro Electricity Distribution Inc. 2011-2014 Cumulative CDM Energy Target:					47.38
Verified Portion of Cumulative Energy Target Achieved (%):					17.95%
LDC Milestone submitted for 2011					-%
Variance					

Appendix 2-I – Data Inputs

4 Year (2011-2014) kWh Target:					
100,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	10.00%	10.00%	10.00%	9.50%	39.50%
2012 CDM Programs		12.00%	11.95%	11.00%	34.95%
2013 CDM Programs			8.52%	8.52%	17.03%
2014 CDM Programs				8.52%	8.52%
Total in Year	**10.00%**	**22.00%**	**30.47%**	**37.53%**	**100.00%**
kWh					
2011 CDM Programs	10,000.00	10,000.00	10,000.00	9,500.00	39,500.00
2012 CDM Programs		12,000.00	11,950.00	11,000.00	34,950.00
2013 CDM Programs			8,516.67	8,516.67	17,033.33
2014 CDM Programs				8,516.67	8,516.67
Total in Year	**10,000.00**	**22,000.00**	**30,466.67**	**37,533.33**	**100,000.00**

- Basic inputs for the top part of Appendix 2-I are the same as for the OPA report.
- With 2011 and 2012 CDM impacts, including persistence out to 2014 are input, the model automatically calculates the incremental savings needed and evenly allocates to 2013 and 2014 to achieve the 4-year target.

Appendix 2-I – Inputs (Continued)

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				net
Persistence of Historical CDM programs to 2014	"Gross" kWh	"Net" kWh	Difference kWh	"Net-to-Gross" Conversion Factor ('g')
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2006 to 2011 OPA CDM programs: Persistence to 2013	0	0	0	0.00%

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast					
	2011	**2012**	**2013**	**2014**	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0.5**	**1**	**0.5**	Utility can select "0", "0.5", or "1" from drop-down list

Appendix 2-I - Outputs

	2011	2012	2013 kWh	2014	Total for 2014
Amount used for CDM threshold for LRAMVA (2014)	9,500.00	11,000.00	8,516.67	8,516.67	37,533.33
Manual Adjustment for 2014 Load Forecast (billed basis)	-	5,500.00	8,516.67	4,258.33	18,275.00
Proposed Loss Factor (TLF)	4.79%	Format: X.XX%			
Manual Adjustment for 2014 Load Forecast (system purchased basis)	-	5,763.45	8,924.62	4,462.31	19,150.37

- Outputs from Appendix 2-I calculate the amount to be used for the LRAMVA and the related but different number for the CDM adjustment.
- If the base forecast is on a system purchased basis, then the loss-adjusted amount should be used; otherwise the billed CDM adjustment is used.
- The distributor must allocate the amounts for the LRAMVA and CDM adjustment to customer classes on a reasonable basis.

Load Forecasting – General Issues (Recap)

- Reasonableness of model(s)
  - From practical and economic theory perspectives
  - Unintuitive variables and coefficient signs
- Data availability and quality
  - Do variables correspond with the drivers for demand in a utility’s service area?
  - Are constructed variables reasonable conceptually?
  - Applies to both historical data and forecasts for the bridge and test years
- LRAMVA
  - Accounting for CDM (particularly 2011 and 2012 CDM programs) in historical data
  - Adjustment for 2013 and 2014 CDM program impacts in test year load forecast
- How good a methodology is needed for a forecast?
  - Depends on utility’s circumstances
- Lack of consistency in approaches complicates the review

2.6.2 – Load Forecast Variance Analysis

- As a check on the accuracy of the distributor’s past load forecasts
- Variance analysis for customers/ connections, kWh, kW, revenues showing:
  - Historical Board-Approved vs. historical actuals
  - Historical Board-approved vs. historical actual (weather-normalized)
  - Historical actual (weather normalized) vs. preceding year
  - Last year historical actual (weather-normalized) vs. bridge year forecast
  - Bridge year vs. Test year

2.6.3 - Other Revenues

- Breakdown of Other Distribution Revenues by accounts (Appendix 2-F)
- Comparison of actual revenues for historical years vs. bridge and test year forecasts
  - Explanations of significant year-over-year variances
- New or changed Specific Service Charges
- Revenues from affiliate transactions, shared services or Corporate Cost Allocation
  - Revenue and Cost accounts must be identified

Questions?

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates
LRAM vs LRAMVA

Josh Wasylyk, Advisor, Natural Gas Applications
July 24, 2013

CDM Guidelines

Board's CDM Guidelines (EB-2012-0003), April 26, 2012

- LRAM = Lost Revenue Adjustment Mechanism

- LRAM history (pre-2011)

- LRAMVA Mechanism for 2011-2014
  - The LRAMVA (Account 1568) captures the difference between net verified CDM savings and the CDM component included in the load forecast

LRAM vs LRAMVA

- What's the difference between LRAM and LRAMVA?
  - How to calculate lost revenues remains the same

$LRAM = Distribution Volumetric Rate (for the applicable rate class) x
Verified Net Savings (kWh or kW)

  - LRAM – (pre-2011):
    - Was a voluntary filing
    - One-sided – no true up in the event that CDM amounts included in rates were not realized
  - LRAMVA (2011-2014):
    - Is a mandatory filing
    - Requires LDCs to compare its net CDM savings to the CDM adjustment it made to its load forecast

LRAM for pre-2011 CDM Activities

- LDCs that have rebased commencing in 2010 are not eligible for LRAM claims for lost revenue associated with the persistence of legacy programs in 2010 and beyond
  - Eligible only if an explicit statement indicating that effects from CDM programs will be dealt with at a later date was included in:
    - CoS Decision
    - Approved Settlement Agreement
  - Expectation that any LRAM claims for the period prior to 2010 have been completed
  - No LRAM claims are expected in 2014 cost of service applications
- Section 13.6 of the CDM Guidelines
- Reinforced through the Board's decisions in the 2012 and 2013 IRM process

LRAMVA Calculation

- LRAMVA
  1) Determine eligible savings for LRAMVA
  2) Calculate lost revenues

(1) Final Verified Net Savings Results (kWh or kW) – CDM Component included in Load Forecast = Eligible Savings (kWh or kW) for LRAM

(2) Eligible Savings (kWh or kW) x Distribution Volumetric Rate (for the applicable rate class) = $LRAMVA

LRAMVA Example #1 – No CDM in load forecast

- LDC-X did not have a CDM component included in last approved load forecast

Example Only

LDC-X LRAM Calculation:

Year: 2012

Calculation:	A		B		C = B-A		D 1		D 2		E = (C x 33% x D1) + (C x 66% x D2)	
	CDM Component of Approved OEB Forecast 2009 CoS		2012 OPA Information: OPA Final Annual Report - 2012		Energy Volume to Calculate Variance		Distribution Volumetric Rate *(Jan - Apr)*		Distribution Volumetric Rate *(May - Dec)*		**Entry for 1568 LRAM Account**	
Customer Class	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	0	0	80,000	15	80,000	15	$0.0139		$0.0139		$1,112.00	
General Service <50 kW	0	0	75,000	25	75,000	25	$0.0120		$0.0120		$900.00	
General Service 50 - 999 kW	0	0	0	0	0	0		$3.2562		$3.2621		$0.00
General Service 1000 - 4999 kW	0	0	0	0	0	0		$1.2490		$1.2512		$0.00
Sentinel Lighting	0	0	0	0	0	0		$59.4148		$59.5217		$0.00
Street Lighting	0	0	0	0	0	0		$5.7139		$5.7242		$0.00
Unmetered Scattered Load	0	0	0	0	0	0	$0.0083		$0.0083		$0.00	
Total	**0**	**0**	**155,000**	**40**	**155,000**	**40**					**$2,012.00**	**$0.00**

Notes:

	A	B	C = B-A	D 1 / D 2	E
	In the OEB Approved forecast (CoS 2009), there were no CDM targets	Above results are **"Net Savings"** taken from OPA's 2012 Final Annual Report *(section 2.5.2 Results- LDC)*	Forecast **less** OPA Reported "Net Savings"	For LDC-X, rates are effective from May 1. OPA Reports are based upon Annual savings, not by month. Therefore have split annual volume by 33% (Jan-Apr) and 66% May-Dec)	Above shows a **Debit** to LDC-X (receivable) due to losing revenue that was not in the LDCs OEB Approved forecast

LRAMVA Example #2 – CDM adjusted load forecast

- LDC-X included a CDM component in its last approved load forecast

LDC-X LRAM Calculations:

Year: 2013 | **Example Only**

Calculation:	A		B		C = B-A		D 1		D 2		E = (C x 33% x D1) + (C x 66% x D2)	
			2013 OPA Information:									
	CDM Component of Approved OEB Forecast 2013 CoS		OPA Final Annual Report - 2013		Energy Volume to Calculate Variance		Distribution Volumetric Rate *(Jan - Apr)*		Distribution Volumetric Rate *(May - Dec)*		**Entry for 1568 LRAM Account**	
Customer Class	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW
Residential	200,000	0	150,000	25	-50,000	25	$0.0139		$0.0140		($696.67)	
General Service <50 kW	75,000	0	70,000	20	-5,000	20	$0.0120		$0.0121		($60.33)	
General Service 50 - 999 kW	190,000	500	100,000	250	-90,000	-250		$3.2621		$3.2655		($816.09)
General Service 1000 - 4999 kW	400,000	800	150,000	400	-250,000	-400		$1.2512		$1.2582		($502.35)
Sentinel Lighting	5,000	20	800	5	-4,200	-15		$59.5217		$59.5267		($892.88)
Street Lighting	150	1	0	0	-150	-1		$5.7242		$5.7292		($5.73)
Unmetered Scattered Load	50	0	10	0	-40	0	$0.0083		$0.0087		($0.34)	
Total	**870,200**	**1,321**	**470,810**	**700**	**-399,390**	**-621**					**($757.34)**	**($2,217.04)**
			Fictitious results						***Fictitious rates***			
Notes:	In the current OEB Approved forecast (CoS 2013), there were CDM targets		Above results are **"Net Savings"** taken from OPA's 2013 Final Annual Report *(section 2.5.2 Results- LDC)*		Forecast **less** OPA Reported "Net Savings"		For LDC-X, rates are effective from May 1. OPA Reports are based upon Annual savings, not by month. Therefore have split annual volume by 33% (Jan-Apr) and 66% May-Dec)				Above shows a **Credit** to LDC-X (payable) due to over-collecting revenue based on higher forecasted CDM results	

When to file LRMAVA recovery?

- CDM Guidelines Section 13.2: Disposition of the LRAMVA, and;
- Chapter 2 & 3 of the Filing Requirements
  - At a minimum, must apply for disposition of the balance in the LRAMVA at the time of COS application
  - May apply annually as part of IRM application, if balance is deemed significant by the LDC

What to file for LRAMVA recovery

- When filing for LRAMVA recovery, the following information needs to be included in your application
  - Final evaluation report from the OPA
    - Verified participation amounts
  - Confirm use of the most recent input assumptions
  - Separate tables, one for each rate class, that shows the net and gross kW and kWh savings of each program, separated by year
  - Separate tables, one for each rate class, that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place

Program Years (Divided by rate class)	Years that lost revenues took place				Total
	2011	2012	2013	2014	
2011	$xxx	$xxx	$xxx	$xxx	$XXX
2012		$xxx	$xxx	$xxx	$XXX
2013			$xxx	$xxx	$XXX
2014				$xxx	$XXX
Total	$XXX	$XXX	$XXX	$XXX	$XXX

What to file for LRAMVA recovery (cont'd)

- LRAMVA supporting information (cont'd):
  - LRAM calculations
    - LRAM variance – calculation of eligible savings (i.e. Final Verified Savings – CDM Component in Load Forecast)
  - Carrying charges (i.e. interest)
  - Rate impacts, including proposed rate riders, by rate class

  Note: A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.
- Continuity schedule will include the LRAMVA Account 1568

Contact Information

- If you have additional questions, please contact
  - Josh Wasylyk, Advisor, Applications:
    - 416-440-7723
    - josh.wasylyk@ontarioenergyboard.ca
  - Market Operations Hotline:
    - 416-440-7604
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Questions

Ontario Energy Board
Commission de l'énergie de l'Ontario

Orientation Session
Electricity Distributors Rebasing for 2014 Rates

Exhibit 7 – Cost Allocation (Then and Now)

Neil Mather, Project Advisor, Electricity Rates
Vincent Cooney, Policy Advisor, Rates, Conservation & Policy Evaluation
July 24, 2013

Cost Allocation Filings: 2010-2014

Cost Allocation – Exhibit 7

- Policy Review [EB-2010-0219]
- Typical Exhibit 7 filings: 2010 and 2014
- Appendix 2-P: 2010 and 2014
- Cost Allocation Model:
  - 2010
  - 2013 (v. 3)
  - 2014 (v. 3.1)

Cost Allocation Policy Review

Report of the Board: "Review of Electricity Distribution Cost Allocation Policy", EB-2010-0219, March 31, 2011

- Required Changes
  - MicroFIT
  - Miscellaneous Revenue
  - Weighting Factors for Services and Billing
  - Transformer Ownership Allowance
  - Revenue to Cost Ratios

- Deferred for study and future development:
  - Allocation by Host Distributor to Embedded Distributor(s)
  - Unmetered Loads
  - Load Displacement Generation

CA Changes: microFIT

MicroFIT

- 11 accounts relevant to microFIT cost responsibility
  - Allocation of 11 accounts, focus on Residential share
  - Calculation of unit cost: total allocated, per customer per month
  - Model accumulates in worksheet O-3.6

- MicroFIT not yet treated as a rate class
  - Revenue is included in Miscellaneous Revenue

- MicroFIT Rate Design
  - Uniform rate updated annually,
  - Source: updated O-3.6 from current applications, together with most recent cost allocation filing from other distributors

CA Changes: Revenue Offset

Miscellaneous Revenue

- Model allocates Revenue Offset amongst rate classes
- Reflect underlying costs to the extent possible
- Allocated amount is included in revenue to cost ratio for each class

- Principle: allocation of revenue should be the same as the allocation of the underlying costs
  - SSS administration is now USoA 4082, allocated by customer count
  - Account set-up is a sub-account of 4235, allocated by weighted number of bills.
  - Pole Rental reflects Primary versus Secondary distribution voltage
  - Most M.I. accounts continue to be allocated by composite allocator (OM&A)

CA Changes: Weighting Factors

Weighting Factors

- Meters (installed cost per customer) and meter reading are calculated from inputs to I-7.1 and I-7.2
- Services (account 1855)
- Billing and Collecting (accounts 5315 – 5330, 5305, 5340)

- Weighting factors are to be based on the applicant's examination of its own relative costs
  - Default weights may be used, with demonstration that alternatives have been examined
- Improved Instructions and examples, included as a worksheet of the model

CA Changes: Transformers

- Revenue Requirement includes the (forecast) cost of transformers owned and provided by the distributor
  - Revenue Requirement does not include the “cost” of the Transformer Ownership Allowance
- Revenue is calculated as (forecast) actual revenue, net of TOA
  - If some customers in a rate class provide their own transformer and others use a distributor-owned transformer, load forecast is split -- revenue is calculated partly at published rate and partly at rate net of TOA
- Data inputs:
  - Revenue: worksheet I-6.1, changed in version 3
  - Cost: worksheet I-8, unchanged

CA Changes: Ratio Policy Range

- Revenue to Cost Ratios
- Range for ratios was narrowed for some classes

Service Class	Range
Residential	85 to 115 %
General Service < 50 kW	80 to 120 %
General Service 50 – 4999 kW	80 to 120 %
Large User	85 to 115 %
Unmetered Scattered Load	80 to 120 %
Street Lighting	70 to 120 %
Sentinel Lighting	80 to 120 %

CA Changes: Ratio Policy Range

- Model now generates "status quo" ratios:
  - Input forecast of charge determinants and current 2013 rates
  - Model calculates class revenue at current rates
  - Does not calculate a ratio using current rates

- Deficiency factor:

$$d = \frac{\text{total base revenue requirement}}{\text{distribution revenue at existing rates}}$$

- Status quo ratios, as if all rates increased by "d"

$$\frac{\text{class revenue at existing rates} \quad \text{X} \quad d}{\text{class revenue requirement}}$$

CA Changes: Host Distributors

- Separate Embedded Distributor Class – no change in policy
  - Use CA model and Appendix 2-P
  - Appendix 2-Q is a useful framework, but not required to file

- Embedded Distributors included in a General Service Class
  - Include as a customer of the class in data inputs: customer count, load forecast, revenue, etc.
  - File Appendix 2-Q; full detail not required
    - Memo to distributors, July 16, 2013

CA - Unmetered Loads Consultation (EB-2012-0383)

WG members included:

- Hydro One Networks, CLD, CHEC, and Innisfil Hydro
- Municipalities: City of Toronto, Brampton, Hamilton, and AMO
- VECC, Energy Probe, Rogers Cable

Consultant's Report issued May 17, 2013

- Outlines consultant's key areas of recommendation
- Includes common sense recommendations** that may warrant consideration in 2014 Cost of Service:
  - Updating data
  - Communication
  - Conditions of Service
  - Cost Allocation Model instructions & examples
  - Terminology and Definitions

***Consultation is ongoing --- Board has not yet opined on the Consultant's Recommendations*

CA - Unmetered Loads Consultation (EB-2012-0383)

Load and Asset Data:

- Adjust billing when updated & vetted kW/kWh data from customer provided
- Fair to expect up or down adjustments, e.g. efficiency improvements **<u>or</u>** additional load(s)

Methodology:

- Derive appropriate Weighting Factors; not default, provide clear narrative
- Connection configuration: "daisy-chaining" should be paired with appropriate factors
- Service weights should reflect true apportionment of work (between customer and distributor)
- Minimum system method – continue to use appropriate customer-related & demand related allocators

Communication:

- Engage customers well in advance of application
- Explain approach to allocation
- Discuss responsibilities, e.g. new technology deployment
- Address customer concerns

Terminology & Definitions:

- Make careful use of Device, Connection, Account, Customer, and other definitions

Cost Allocation Filings: 2010-2014

- **Exhibit 7, then and now:**
  - Summary description, highlighting re-balancing (if any)
    - 2010 example: 135 pages of 760 total
    - 2013 example: 20 pages of nearly 2000 total
- **Appendix 2-P, then and now:**
  - 1 page then (WORD) versus 2 pages now (Excel)
  - Revenue to cost ratios:
    - Then: 2 ratios: "before & after"
    - Now: 3 ratios: existing, "status quo", proposed (test year)
- **Appendix 2-Q**
    - Provides sharper focus on embedded distributor(s) than CA model
      - Information required of host distributor, if no separate class of embedded distributor(s)
- **Cost allocation model, then and now**
    - Then: rolled-up version okay; print of all input and output sheets
    - Now: live Excel spreadsheet required

Cost Allocation Framework

Conceptual Framework unchanged, basic Model little changed

- Customer Classes: worksheet I2
- Functionalization
  - Preparing USoA account forecast data
  - Worksheets: I-3 (trial balance forecasts); I-4 (asset sub-accounts where required)
- Categorization:
  - Accounts by demand-related, customer-related, partial (minimum system)
  - Worksheets: E1; I-5.1 cell D21
- Allocation:
  - Allocator for each account: policy effected in worksheet E-4
  - Allocator values (allocation to all classes adds to 100%): worksheet E-2
  - Data Input: worksheets I-5, I-6, I-7, I-8, I-9
  - Detailed calculations: worksheets O-4, O-5, O-6, O-7
  - Main results: worksheets O-1, O-2
  - Other results: O-2.1 – 2.5; O-3.1 – 3.5
  - microFIT unit cost (worksheet O-3.6) new with version 3.0

Rate Re-balancing

- Applicant provides Appendix 2-P:
    1. Approved revenue-to-cost ratios
    2. Status quo ratios
    3. Proposed ratios

- Policy is unchanged: if any status quo ratio is outside the Board's policy range, proposed rates must adjust to produce a ratio in the applicable range

- Applicant may propose:
    - movement within range
        - expected outcome: direction of any movement is toward 100%
    - movement to include subsequent (IRM) years to mitigate impacts
        - proposed and approved as part of the COS proceeding

CA Model: version 3.1 vs. 3.0

Version 3.1

- Updated list of accounts in worksheet I-3 'Trial Balance'
  - Removes formula from version 3.0 for annual recovery of PP&E balance
  - Recovery of Accounts 1575, 1576 by rate rider in 2014
    - Memo June 25, 2013
- Direct Allocation
  - provides for inclusion of overhead costs in revenue requirement
- Easier to use:
  - Clearer instructions
    - especially re Weighting Factors
  - New colour coding on worksheet I-3

Questions?