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

Case Management and Contacts

Jane Scott

July 25, 2017

Applications Division

Major Applications
Jane Scott

- Case Managers; COS & CIR
- Subject Matter Experts e.g. DSP, Cost Allocation

Incentive Rate-setting and Regulatory Accounting
Dan Gapic

- Case Managers; IRM
- Regulatory Accountants

Supply & Infrastructure
Nancy Marconi

- Case Managers; OPG, MAADs, Leave to Construct
- Subject Matter Experts, e.g. Pole Attachments, RPP

Application Policy & Climate Change
Pascale Duguay

- Case Managers; CDM, DSM
- Subject Matter Experts, e.g. Cost of Capital, Load Forecasting, LRAMVA

Meet Your Case Contact

Orientation Session	Case Contact
January 1, 2018 Filers (4)	
Centre Wellington Hydro Ltd.	Fiona O'Connell
Cooperative Hydro Embrun Inc.	Georgette Vlahos
Hydro Hawkesbury Inc.	Birgit Armstrong/Rachel Anderson
Westario Power Inc.	Donald Lau
May 1, 2018 Filers (9)	
Espanola Regional Hydro Distribution Corporation	Donald Lau
Erie Thames Powerlines Corp.	Fiona O'Connell
Essex Powerlines Corporation	Khalil Viraney
Hydro 2000 Inc.	Andrew Frank
Hydro One	Harold Thiessen
Hydro One Remote Communities Inc.	Georgette Vlahos
Lakeland Power Distribution Ltd.	Birgit Armstrong
Orillia Power Distribution Corp.	Harold Thiessen
PUC Distribution Inc.	Martin Davies
Sioux Lookout Hydro Inc.	Lawrie Gluck

Meet Your Case Contact

Orientation Session	Case Contact
January 1, 2019 Filers (4)	
Chapleau Public Utilities Corporation	Lawrie Gluck
Greater Sudbury Hydro Inc.	Donald Lau
Kitchener-Wilmot Hydro Inc.	Birgit Armstrong
Oakville Hydro Electricity Distribution Inc.	Khalil Viraney
May 1, 2019 Filers (9)	
Bluewater Power Distribution Corp.	Georgette Vlahos
Burlington Hydro Inc.	Donald Lau
COLLUS PowerStream Corp.	Andrew Frank
Energy + Inc.	Khalil Viraney
ENWIN Utilities Ltd.	Lawrie Gluck
Fort Frances Power Corporation	Harold Thiessen
Midland Power Utility Corporation	Fiona O'Connell
Niagara-on-the-Lake Hydro Inc.	Birgit Armstrong
Orangeville Hydro Limited	Andrew Frank
Veridian Connections Inc.	Martin Davies

ONTARIO ENERGY BOARD

Role of Registrar & Consumer Engagement Framework

Orientation Session
Electricity Distributors Rebasing for 2018 Rates

Rudra Mukherji, Associate Registrar

July 25, 2017

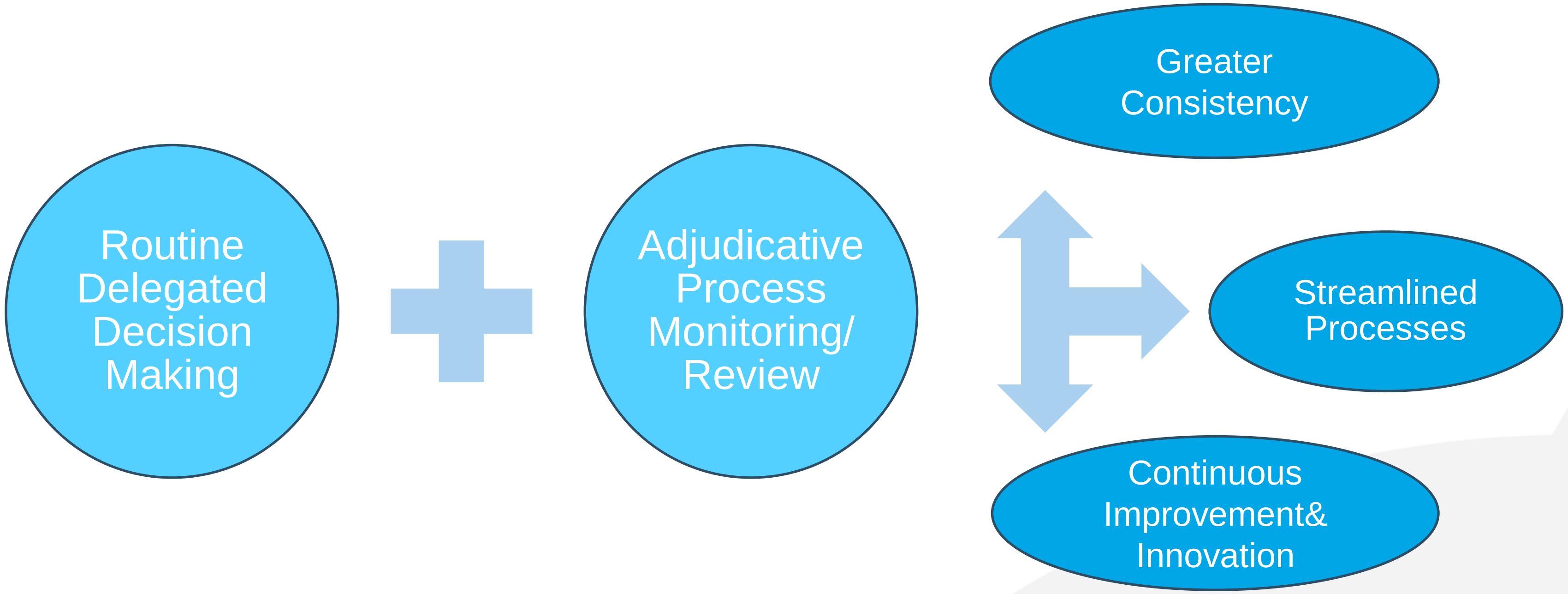
Agenda

1. Role of Registrar

2. Consumer Engagement Framework

3. Questions

Role of Registrar



Registrar – Delegated Decision Making

- **Delegated decision-making**
- **All applications that are not otherwise delegated under s. 6(1)**
  - Issue notice
  - Issue PO#1

Registrar – Delegated Decision Making

- **Completeness**
  - Check against Filing Requirements
  - Decision on completeness of application

- **Notice**
  - Determination of appropriate publication
  - Receive and consider requests for:
    - Intervenor status
    - Cost eligibility

- **Procedural Order No. 1**
  - Decision on intervenor and cost eligibility requests
  - Set out schedule for hearing
  - Incorporating consumer engagement steps where necessary/appropriate
  - Decision on oral vs written hearing made by the Panel

Registrar – Adjudicative Process

- **Support and enhance regulatory efficiency and consistency by**:
  - Monitoring adjudicative process
  - Identifying and addressing process related issues
  - Ensuring the OEB's processes are serving the needs of all participants (OEB, Board Members, staff, stakeholders, applicants, intervenors)
  - Reviewing and amending Rules and Practice Directions as/when necessary
  - Innovating where better processes are known/identified

Consumer Engagement Framework

Ontario

Consumer Engagement Framework
Purpose, Goal and Design

- ***Purpose***: The Consumer Engagement Framework is the OEB's enhanced approach to engage with and empower energy consumers in the OEB's adjudicative/hearing process

- ***Goal***: Ensure that the people who pay the energy bills have a stronger and more meaningful voice throughout OEB hearing process

- Framework elements ***designed*** to:
    - build consumer **awareness** about the OEB
    - provide consumers with simple and meaningful **information**
    - make it easier for consumers to **access** and participate in OEB processes

Consumer Engagement Framework

Current Engagement Tools	New Engagement Tools
• Legal notice • Letters of comment • Follow a proceeding • Online access to documents • Attend/listen-in to a hearing • Intervention • Required utility consumer consultation (pre-filing)	• Community Meetings • Enhanced Notification • OEB Contact Person • Enhanced Consumer Website • Hearing Guidebook & Quicktools • Community Hearings

Tools: Community Meetings

- Community meetings give customers opportunity to:
  - Find out about the OEB and the hearing process
  - Learn more about the application that has been made and the reasons behind the request
  - Get involved by providing comments or asking questions

- Held for (electricity and gas) Custom IR and Cost of Service (COS) applications
  - 15 community meetings for 12 utilities that filed COS or Custom IR applications for 2017 rates
  - So far utilities filing for 2018 electricity rates:
    - Hydro One - 10 community meetings (9 face-face meetings and 1 Province-wide tele-meeting)
    - Centre Wellington Hydro – planned for September
    - Co-operative Hydro Embrun – planned for September

Tools: Community Meetings

- Community meetings are hosted and organized by the OEB
- Scheduled after Notice and before PO 1
- May be more than one meeting depending on service area
- Meetings are led by the Office of the Registrar
- Dedicated Public Affairs team coordinates logistics and advertising
- Case Manager initiates contact with utility to discuss meeting logistics
- A complete information package provided to utility

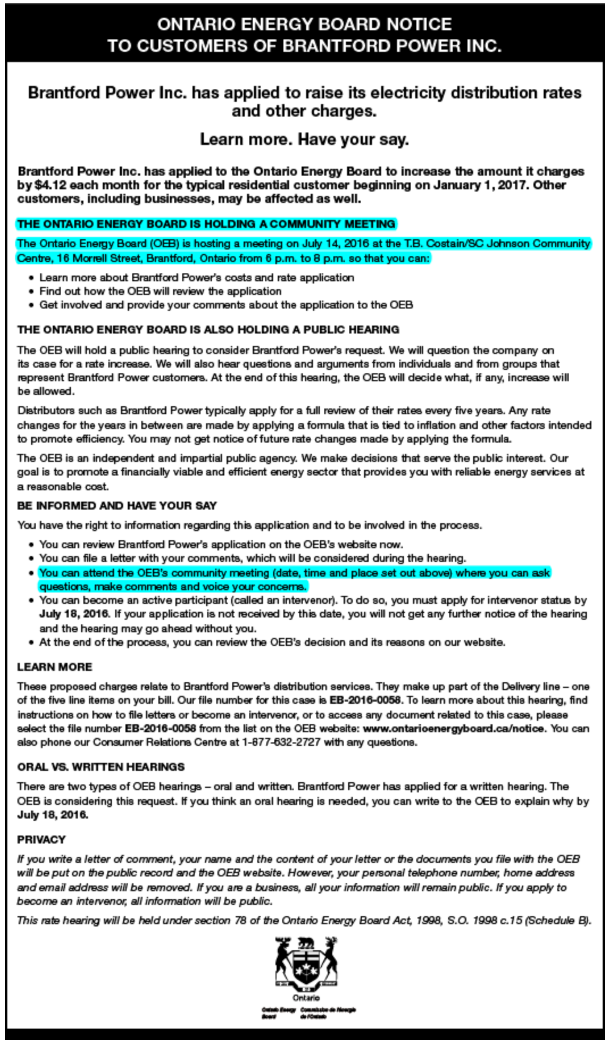
Tools: Community Meetings

- While the OEB hosts and organizes the meeting, the utility is expected to:
  - Assist in determining appropriate date and venue
  - Cooperate with OEB staff to determine appropriate channels for advertising the meeting to maximize customer participation
  - Prepare one or more poster boards (scorecard, major application asks, etc.)
  - Attend the meeting
  - Have one or more executives deliver a presentation about the applications – relief requested and rationale for the requests

Tools: Notification

- The OEB is leveraging new and existing notification tools, using multiple channels to reach out to consumers about engagement opportunities:
  - Bill inserts for OEB's community meetings
  - E-mail
  - Voice Blasts
  - Social media - twitter (and re-tweets)
  - Websites (OEB and utility) – often other community-based organizations also agree to post
  - Newspaper ads
  - Radio spots
  - Community bulletin boards
  - Direct calls to local organizations (e.g. BIAs, Chamber of Commerce, municipal, provincial and federal government reps, grassroots and cultural organizations)
  - Direct mail

Tools: Notification -
Legal Notice & Community Meeting Ads



ONTARIO ENERGY BOARD NOTICE
TO CUSTOMERS OF BRANTFORD POWER INC.

Brantford Power Inc. has applied to raise its electricity distribution rates and other charges.

Learn more. Have your say.

Brantford Power Inc. has applied to the Ontario Energy Board to increase the amount it charges by $4.12 each month for the typical residential customer beginning on January 1, 2017. Other customers, including businesses, may be affected as well.

THE ONTARIO ENERGY BOARD IS HOLDING A COMMUNITY MEETING

The Ontario Energy Board (OEB) is hosting a meeting on July 14, 2016 at the T.B. Costain/SC Johnson Community Centre, 16 Morrell Street, Brantford, Ontario from 6 p.m. to 8 p.m. so that you can:

- Learn more about Brantford Power's costs and rate application
- Find out how the OEB will review the application
- Get involved and provide your comments about the application to the OEB

THE ONTARIO ENERGY BOARD IS ALSO HOLDING A PUBLIC HEARING

The OEB will hold a public hearing to consider Brantford Power's request. We will question the company on its case for a rate increase. We will also hear questions and arguments from individuals and from groups that represent Brantford Power customers. At the end of this hearing, the OEB will decide what, if any, increase will be allowed.

Distributors such as Brantford Power typically apply for a full review of their rates every five years. Any rate changes for the years in between are made by applying a formula that is tied to inflation and other factors intended to promote efficiency. You may not get notice of future rate changes made by applying the formula.

The OEB is an independent and impartial public agency. We make decisions that serve the public interest. Our goal is to promote a financially viable and efficient energy sector that provides you with reliable energy services at a reasonable cost.

BE INFORMED AND HAVE YOUR SAY

You have the right to information regarding this application and to be involved in the process.

- You can review Brantford Power's application on the OEB's website now.
- You can file a letter with your comments, which will be considered during the hearing.
- You can attend the OEB's community meeting (date, time and place set out above) where you can ask questions, make comments and voice your concerns.
- You can become an active participant (called an intervenor). To do so, you must apply for intervenor status by **July 18, 2016**. If your application is not received by this date, you will not get any further notice of the hearing and the hearing may go ahead without you.
- At the end of the process, you can review the OEB's decision and its reasons on our website.

LEARN MORE

These proposed charges relate to Brantford Power's distribution services. They make up part of the Delivery line – one of the five line items on your bill. Our file number for this case is **EB-2016-0058**. To learn more about this hearing, find instructions on how to file letters or become an intervenor, or to access any document related to this case, please select the file number **EB-2016-0058** from the list on the OEB website: **www.ontarioenergyboard.ca/notice**. You can also phone our Consumer Relations Centre at 1-877-632-2727 with any questions.

ORAL VS. WRITTEN HEARINGS

There are two types of OEB hearings – oral and written. Brantford Power has applied for a written hearing. The OEB is considering this request. If you think an oral hearing is needed, you can write to the OEB to explain why by **July 18, 2016.**

PRIVACY

If you write a letter of comment, your name and the content of your letter or the documents you file with the OEB will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public. If you apply to become an intervenor, all information will be public.

This rate hearing will be held under section 78 of the Ontario Energy Board Act, 1998, S.O. 1998 c.15 (Schedule B).

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Tools: Notification

- For rate applications, the utility is instructed (through Letter of Direction) to tweet the link of the legal notice.

- For community meetings, the OEB and utility currently tweet about the meeting.

Tools: OEB Contact Person

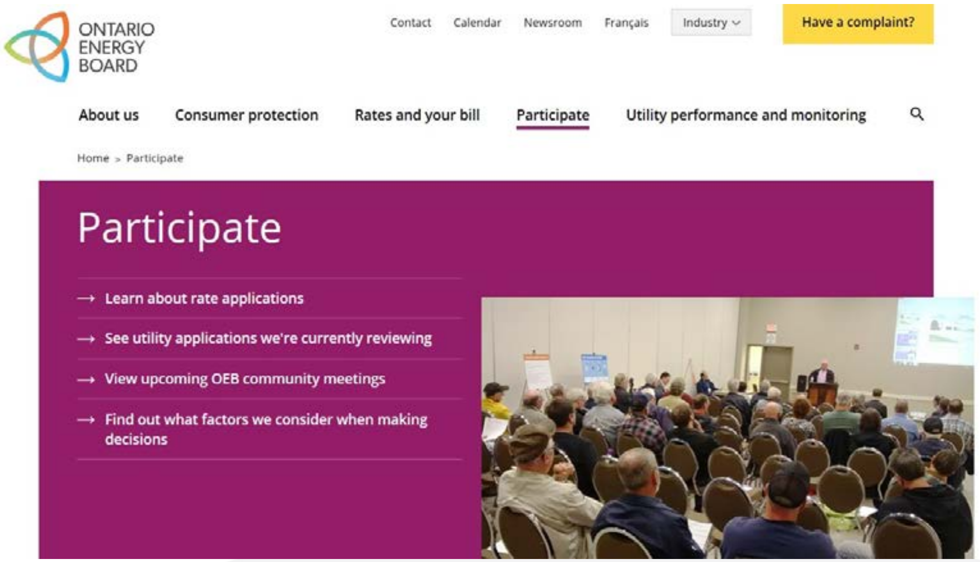
- A designated subject matter expert to assist customers to:
  - Better understand the particulars of a specific application/notice
  - Determine how they are affected by the application
  - Determine whether and how they might wish to become involved in the OEB's review process

Tools: Enhanced Consumer Website

- In 2017, the OEB launched its enhanced consumer website
- Enables customers to more easily obtain information about Ontario’s energy sector and how to get involved in OEB processes
- The website provides:
  - a landing page for major applications
  - a list of upcoming and recently completed community meetings with links to the ads and the OEB Staff Reports

Tools: Enhanced Consumer Website

- OEB Consumer Website – ‘Participate’ tab includes links about:
    - How the hearing process works
    - Current major rate application and related notices
    - How to get involved in the hearing process
    - Community meetings (upcoming and recent)



Tools: Enhanced Consumer Website

‘Community Meetings’ tab includes list of upcoming and recent:

- Meeting ad, date, time and location
- Link to register to attend
- Links to meeting summaries, presentations
- Final OEB decision

See upcoming community meetings. We come to you to explain who we are, what we do, and what your utility has asked us to approve.

We host local community meetings so that you have a chance to share your thoughts and ask questions about things your local utility has asked the Ontario Energy Board to approve, such as an increase in the rates they charge for the delivery of electricity or natural gas.

You can learn why your utility is asking for changes and how it justifies them. This is your opportunity to ask hard questions about your utility’s costs. You can give us your input directly, which we will take into consideration as part of our decision-making process.

Upcoming community meetings

Sorry, no upcoming community meetings at this time.

Recent meetings

Hydro One Networks Inc. - OEB Community Meeting - Province-wide Telemeeting

Wednesday, July 12, 2017
6:30 pm - 8:30 pm
All Hydro One customers are invited to call in to a province-wide Telemeeting.

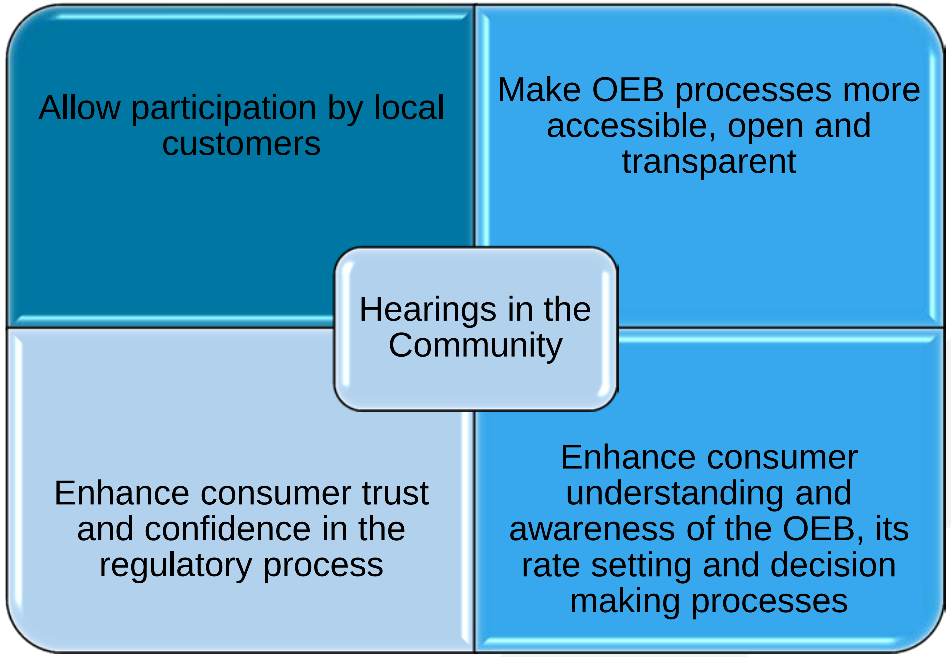
- Call, toll-free 1-800-806-5484, Pass Code 8940608#
- Online, send us an email at ConsumerVoice@oeb.ca and we’ll send you the link
- Register for this event

Tools: Guidebook/Quicktools

- Guidebook is currently under construction
- Plain-language, easy-to-use guide made up of a number of interactive web-based “quick tools”
- Availability:
  - Hard copy
  - Distributed at public meetings
  - Utility
  - Enhanced consumer website - supplemented with more interactive media such as videos and tutorials
- Passive and non-intimidating way for customers to see first-hand how the OEB goes about its work and how they can get involved at each step of the process

Tools: Hearings in the Community

- OEB will hold some major hearings (in whole or part) in a local community impacted by an application
- Pilot currently being planned



Questions???

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

CoS Filing Requirements – 2017 Update for 2018 Applications

Summary of Key Changes

Martin Davies

July 25, 2017

Cost of Service Applications for 2018 - 1

- January 1, 2018 Rates:

	Expected/Filed Date	Status
Centre Wellington Hydro Ltd.	20-Jun-17	Complete
Cooperative Hydro Embrun Inc.	22-Jun-17	Complete
Hydro Hawkesbury Inc.	12-Jul-17	Under Review
Westario Power Inc.	30-Jun-17	Pending

Cost of Service Applications for 2018 - 2

- May 1, 2018 Rates:

	Expected/Filed Date	Status
Erie Thames Powerlines Corp.	28-Aug-17	Pending
Essex Powerlines Corp.	28-Aug-17	Pending
Hydro 2000 Inc.	28-Aug-17	Pending
Hydro One Remote Comm. Inc.	28-Aug-17	Pending
Lakeland Power Distribution Ltd.*	28-Aug-17	Pending
PUC Distribution Inc.	28-Aug-17	Pending
Sioux Lookout Hydro Inc.	28-Aug-17	Pending

* Deferral Requested

Chapter 2 – Key Changes

- Changes to Existing Sections
  - Duplications with Rate Handbook removed or condensed
  - Clarification of relevance of Chapter 2 to Custom IR applications
  - Materiality thresholds clarified (2.0.8 and 2.9)
  - Other pensions and benefits section updated for policy change (2.4.3.1)
  - Distributor Consolidation (2.1.9)
  - Costs of Eligible Investments for the Connection of Qualifying Generation Facilities (2.2.2.5)
  - Accounting changes
  - Required Information for Capital Expenditures (2.2.2.2) – address Rate-funded Activities to Defer Distribution Infrastructure
  - Conservation and Demand Management (CDM) section (2.4.6)

- No new sections added
- Relatively few changes to Models and Appendices

Duplication with Rate Handbook

- Previous version of Filing Requirements had significant amount of content that is duplicative of October 13, 2016 Rate Handbook
  - Removed or condensed the duplicative information from the Filing Requirements
    - Sections 2.0 – General Requirements, 2.2.2.1 Planning and 2.4 Operating Expenses
  - Trying to keep policy out of the Filing Requirements and make them more a listing of what is required in the application

Relevance to Custom IR applications

- Clarification from last years Chapter 2 that if filing a Custom IR application which is underpinned by a cost of service test year(s), the utility must file all necessary documentation for a CoS application, including the Chapter 2 appendices and the relevant models

Materiality Thresholds Clarified

- Section 2.0.8
  - Thresholds have not been changed, but clarification has been provided that they apply to changes in rate base, capital expenditures and OM&A <u>if the revenue requirement impact exceeds the threshold as follows:</u>
    - $50,000 for a utility with a revenue requirement less than or equal to $10M
    - 0.5% of revenue requirement for a utility with a revenue requirement greater than $10M or less than or equal to $200 million
    - $1M for a utility with a revenue requirement of more than $200M
- Section 9 – Deferral and Variance Accounts
    - The above materiality thresholds are applicable for approving new Group 2 deferral and variance accounts

Updates for Policy Changes-OPEBs

- Pensions and Other Post-Employment Benefits (OPEBs) Consultation (2.4.3.1)
  - FRs have been updated to reflect the Report of the OEB on Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, issued May 18, 2017
  - Establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost based applications
  - If the applicant is proposing to include pension and OPEB expenses based on the cash method, sufficient supporting rationale and evidence is required
  - If the applicant is proposing to change the basis on which pension and OPEB expenses are accounted for from its last rebasing application, it must quantify the impact of the transition
  - Appendix 2-KA has been eliminated

Changes to Existing Sections

- Distributor Consolidation (2.1.9)
  - Addition reminding distributors that if they have acquired or amalgamated with any other distributors since the last rebasing application, the Handbook to Electricity Distributor and Transmitter Consolidations, issued January 19, 2016 should be consulted for further details on rebasing after consolidation
  - New Requirement that the consolidating distributor should also detail the actual savings as a result of consolidation compared to what was in the approved consolidation application and explain how these savings are sustainable and the efficacy of any rate plan approved as part of a MAADs
  - Reminder that the requirement to file a distribution system plan every five years still applies even if a consolidation application has been filed or approved

Renewable Generation Facility Funding Request

Renewable Generation Facilities (2.2.2.5)

- The Burden Reduction Act, 2017 Schedule 10, Section (5) amended section 79.1 (1) which required the OEB to provide rate protection for costs incurred to make an eligible investment in order to connect a qualifying generation facility; amended from ‘shall provide’ to ‘may provide’
- Addition stating that the OEB will only require rate protection when the annual amount of revenue requested is above the materiality thresholds as detailed in section 2.0.8

Commodity Related Updates

- Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589,* applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts
- New GA Analysis Workform to reconcile the payments made for GA against the amounts billed to LDCs by the IESO
- Certification of accounts 1588 and 1589 by the CEO, CFO, or equivalent now required

Transition to IFRS

- If a LDC has not rebased since 2013, when the changes to capitalization and useful lives were mandated, then the impact of such changes are required in the 2018 application
- If a LDC has not rebased since 2015, when the change to IFRS was required and there have been additional changes than those in 2013, then the impact of such changes are required in the 2018 application

Other Changes to Existing Sections

Capital Expenditures (2.2.2)

- Changes made to section on Rate-funded Activities to Defer Distribution Infrastructure
- Distributors must describe how for all capital projects required to address capacity constraints they have considered incremental conservation initiatives
- Distributors may apply to the OEB for funding through distribution rates for four types of activities:
  1. CDM programs that target distributor-specific peak demand (kW) reductions to address a local constraint of the distribution system
  2. Demand response programs whose primary purpose is peak demand reduction in order to defer capital investment for specific distribution infrastructure
  3. Distribution system efficiency improvement and distribution loss reduction
  4. Energy storage programs whose primary purpose is to defer specific capital spending for the distribution system

CDM

- Conservation and Demand Management
  - Section 2.4.6 in Chapter 2 has been updated to clarify that DR3 savings should generally not be included in the LRAM savings unless supported by empirical evidence to be reviewed in a CoS application
  - Section 2.4.6.2 in Chapter 2 has been updated to enhance the reporting of LRAMVA application details and reflect the detailed instructions from the LRAMVA workform in the guidelines
  - LRAMVA workform (version 2.0) now allows LDCs to input and use more accurate, initiative-level persistence and savings adjustment data provided by the IESO
  - LRAMVA workform has enhanced functionality and more explicit instructions on the treatment of IESO verified savings adjustments and use of the LRAMVA threshold

Rate Mitigation

- New section 2.8.12.1 *Residential Rate Design* provides clarification of mitigation requirements for the transition of residential customers towards fully fixed rates

- Section 2.8.12.2 *Mitigation Plan Approaches* is now less prescriptive, allowing the applicant more leeway to propose its own approach to mitigation where it is necessary

Questions?

Ontario Energy Board

Commission de l'énergie de l'Ontario

Preparing Your Application – Some Dos and Don'ts From Staff

July 25, 2017

Georgette Vlahos
Birgit Armstrong

The Application

- **Do file the application according to suggested time table for rates effective January 1 and May 1**
  - Ensures that there is enough time for the application to be considered and adjudicated by the OEB
  - Consider including a request for interim rates in the application, if it appears that the rate order will be issued after the effective date

- **Do check that the application conforms to the applicable Filing Requirements**
  - Overall presentation and sequencing of exhibits
  - All appendices completed
  - Use the CoS checklist

- **Do identify information requested in the Filing Requirements that is missing and provide an explanation**
  - Saves time for both the applicant and the OEB

- **Do include mitigation plans for any rate class where the total bill impact exceeds 10% or the impact of the change to fixed rates is over $4**
  - Bill impacts as calculated in the Tariff and Rate Impact Model

The Application continued

- **Do file a redacted version of confidential material or a non-confidential summary, in keeping with the OEB's Practice Direction on Confidentiality**
  - If parties can refer to a thorough non-confidential version, it avoids two versions of submissions and usually avoids in-camera sessions of oral hearings

- **Do check that the evidence is internally consistent and explain when it is not**
  - OM&A in operating expenses vs OM&A in RRWF
  - Number of FTEs and customers (average or year-end)
  - Bill impacts referenced in exhibit 1 or cover letter with bill impacts presented in Tariff and Rate Model

- **Don't skip steps when explaining how a forecast was developed**
  - Importance of the narrative

- **Do ensure that the numbering system for exhibits in the application is complete and systematic with no inconsistencies or missing sections**
  - Tables should be numbered
  - Evidence referred to in one exhibit doesn't exist or is different

The Application continued

- **Do avoid generic descriptions**
  - Revenue requirement (specify service or base)
  - Load forecast (specify purchased or billed)

- **Don't call everything Appendix A**
  - Differentiate especially if it is a report that already has an Appendix A

- **Do name Excel sheets clearly**
  - Not Attachment F.xlsx but Attachment F_RRWF.xlsx

- **Don't submit print versions of uninformative pages from OEB models**
  - Such as the entire Cost Allocation model – only file a hardcopy of input sheets I-6 and I-8 and output sheet 0-1 and 0-2

The Application continued

- **Do limit repeating large tracts of text**

- **Do clearly indicate the date of update on any updated documents**
  - E.g., when updating a table in an interrogatory response, do give the revised table a new number, and note in the title which table it replaces (e.g., IRR VECC#20 Table 5, replaces Exh4-Table 4.11)

- **Do ensure that the Cost Allocation model contains updated numbers and isn't just a copy of a model submitted in a prior proceeding**

Interrogatories and Submissions

- **Do read all interrogatories carefully so you fully understand the question before you begin the answer**
  - Be sure to answer the question(s) asked, specifically and clearly and try not to go off into the weeds
  - Call your case manager or the intervenor if a question is unclear or ambigous.

- **Do respond to interrogatories using the accurate reference to the evidence and interrogatory**
  - Rule 26.02(e) sets out the correct numbering sequence for interrogatories and responses, e.g. IRR 2-Staff-4

- **Group the responses together according to the issue to which they relate**

- **Do organize and respond to interrogatories by issue (or topic per the exhibits in the filing requirements)**
  - Within each issue or topic, group the responses by party

Interrogatories and Submissions continued

- **Don't answer a duplicate interrogatory twice**
  - just answer by referring the duplicate interrogatory to the IR response that contains the answer

- **Do review the point being made by OEB staff and/or intervenors carefully in their submission and address that point as clearly and concisely as possible**
  - Use appropriate evidence references to back up your argument
  - Try to articulate a position for every area covered by an intervenor and OEB staff, even if it is to say that you have no particular position on an issue

General

- **When updating evidence: Do communicate with the case manager when filing an update**
  - Normally the revision filed through RESS retains the same name but with the new date

- **When requesting an extension: Don't wait until the day of the deadline to file a request for an extension to a regulatory deadline**
  - A request for a reasonable extension, with sufficient explanation, is more credible and easier to move through the approval process if made a day or two in advance

- **When settlement has been reached in your proceeding: Do ensure that you carefully document all relevant related issues to the settled item and underlying calculations**
  - E.g., ensure a Rate Base Settlement specifically mentions the Working Capital amount or under OM&A allocate the total settlement amount into the five summary categories so as to provide a sound basis for future reference and analysis

Fair Hydro Act

Cost of Service Orientation

July 25, 2017

Overview of Fair Hydro Act

- The *Fair Hydro Act, 2017* (FHA) came into force on June 1. It puts in place the framework for giving effect to the government's stated Fair Hydro Plan initiatives to:
  - Lower electricity bills by 25% on average for all residential consumers, and as many as half a million small businesses and farms
  - Hold electricity bill increases to the rate of inflation for 4 years
  - Remove the cost of certain electricity-related relief programs (RRRP and OESP) from electricity bills, and instead funds those programs through taxes
  - Provide additional bill relief for residential customers in rural or remote areas of the province and for on-reserve First Nations residential customers

- Bill reductions that are not funded through taxes will largely be achieved through the refinancing of a portion of the costs of the Global Adjustment (GA)
- In later years, the cost of this refinancing will be recovered through adjustments to electricity bills called a Clean Energy Adjustment

OEB Responsibilities under the FHA

- The OEB has a number of new or modified responsibilities under the FHA, many of which are relevant to LDC billing and settlement activities in particular:
  - Setting RPP prices to give RPP consumers the benefit of their “fair adjustments” over the coming years (initial reduction and holding increases to rate of inflation)
  - Setting a “GA modifier” to give eligible consumers that are not on the RPP their fair adjustments over the coming years
  - Setting the rates by which the cost of the GA refinancing will be recovered
  - Approving fees that can be charged by OPG as the Financial Services Manager (regulations may provide for the ability to recover costs and expenditures and to earn a return)
  - Enforcing compliance with the FHA by electricity distributors and unit sub-meter providers
  - Calculating the revised RRRP charge
  - Determining the maximum distribution charge for the eight named LDCs whose customers receive Distribution Rate Protection

Customers Eligible for Fair Adjustments

- Customers eligible for “fair adjustments” are called “specified consumers” in the FHA:
  - These are the same consumers as are eligible for the 8% rebate under the *Ontario Rebate for Electricity Consumers Act, 2016* (ORECA)
    - Consumers on RPP
    - Consumers eligible for RPP but opted out for retail contract or market-based SSS pricing
    - Consumers not eligible for RPP but eligible for the 8% ORECA rebate (see OEB’s February 9, 2017 letter providing guidance re the 8% rebate)
    - Consumers served by unit sub-metering providers
  - These eligible consumers will receive their fair adjustments in different ways depending on how they buy their electricity
    - For consumers on RPP, through their RPP prices
    - For consumers not on RPP, through the “GA modifier”
    - For consumers served by a unit sub-metering provider, as a pass-through of the fair adjustment applied to the bill for the sub-metered building
- “Specified consumers” are also those that will pay Clean Energy Adjustment amounts in the future to recover the cost of the GA refinancing

Setting RPP Prices & the GA Modifier

- Eligible consumers that are on the RPP will see their fair adjustments largely through their RPP prices
  - The OEB set RPP prices to give effect to the government's commitment to lower electricity bills on average by 25%
  - As required by the FHA, the calculation was done by reference to a "proxy" consumer that has certain attributes set out in a regulation - essentially a Toronto Hydro residential customer on TOU prices using 750 kWh of electricity every month, not on equal billing, not receiving OESP payments, etc.
  - The OEB set new RPP prices that result in this proxy customer having a bill that is 25% lower than what the bill would otherwise have been on May 1 without consideration of the FHA
- Eligible consumers that are not on the RPP will see their fair adjustments largely through a reduction in their GA charges in each billing period via the GA modifier set by the OEB
  - The GA modifier has been set at $32.90/MWh, an amount which mirrors the difference in electricity supply cost in the proxy consumer's bill
- The RPP prices and the GA modifier will be in effect until April 30, 2018
  - At that time, the OEB will reset RPP prices and the GA modifier for the period May 1, 2018 to April 30, 2019 in a way that holds increases to the rate of inflation in accordance with the FHA

Implementation Issues

- The OEB's June 29th letter provides guidance regarding the implementation of the FHA. Among other things:
  - Re: the RPP:
    - The Final RPP Variance Settlement Amount mechanism has been suspended, and the FSVA is not to be charged or credited to any customer that leaves the RPP on or after July 1, 2017
  - Re: the GA modifier:
    - The GA modifier is to be applied to the loss-adjusted volume of electricity distributed to the customer in the billing period
    - Distributors must still comply with O. Reg. 429/04 in relation to the GA, subject to reflecting the application of the GA modifier. Among other things, for a low-volume customer this requires separate GA calculations for metered consumption (i.e., exclusive of losses) and for the volume of losses, as has been the case since July 2015 (see the OEB's June 9, 2015 staff Bulletin)
    - The GA as adjusted by the GA modifier is what is to be used for invoicing purposes
- Additional guidance:
  - A non-RPP customer that is eligible for a fair adjustment remains eligible even if they opt in to Class A
  - The July 1 RPP price adjustment is a material change for customer bills. As such, distributors should be adjusting equal monthly payment and equal billing amounts to reflect that change when they do their next quarterly or semi-annual review

Legacy Rural or Remote Rate Protection

- Under the FHA, the RRRP funding for eligible rural customers of Hydro One Networks (the R2 rate class) will move from the RRRP charge to provincial revenues
- This is about $243M out of the approximately $290M in the RRRP funding pool for 2017
- All grid-connected customers will see a decrease in the RRRP charge from $0.0021/kWh to $0.0003/kWh for electricity consumed on or after July 1, 2017
- Remaining charge is for Algoma, HONI Remotes and First Nations
- The regulation also set the credit at $60.50/month until the end of 2017
    - For each subsequent year, the OEB will calculate a revised RRRP charge in accordance with the rules set out in a regulation

Distribution Rate Protection

- The FHA names eight distributors whose residential customers will have their monthly base distribution charge capped
    - The eight utilities are: Atikoken, Algoma, Chapleau, InnPower, Sioux Lookout, Hydro One (R1 and R2), Lakeland (Parry Sound) and Northern Ontario Wires
    - The base distribution charge consists of the base monthly fixed service charge and base variable distribution charge
- The OEB will calculate the cap or maximum monthly base distribution charge based on the parameters outlined in the DRP regulation
    - For July 1, 2017 the cap was based on the minimum fully fixed distribution charge for the named utilities that had approved 2017 rates
    - The maximum charge is $36.43
    - Will be updated at least once a year but will not go down

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

Orientation Session
Electricity Distributors' Rebasing for 2018 Rates

Consolidated Distribution System Plans

Keys to Success

Donald Lau
July 25, 2017

What is a Distribution System Plan?

- Consolidated stand alone document
- Asset condition assessment
- Linked to proposed budget
- Consider conservation, smart grid, renewable generation, regional planning, and public policies
- Deliver value to customers
- Effective management of assets
- Optimized plan
- Project prioritization and pacing

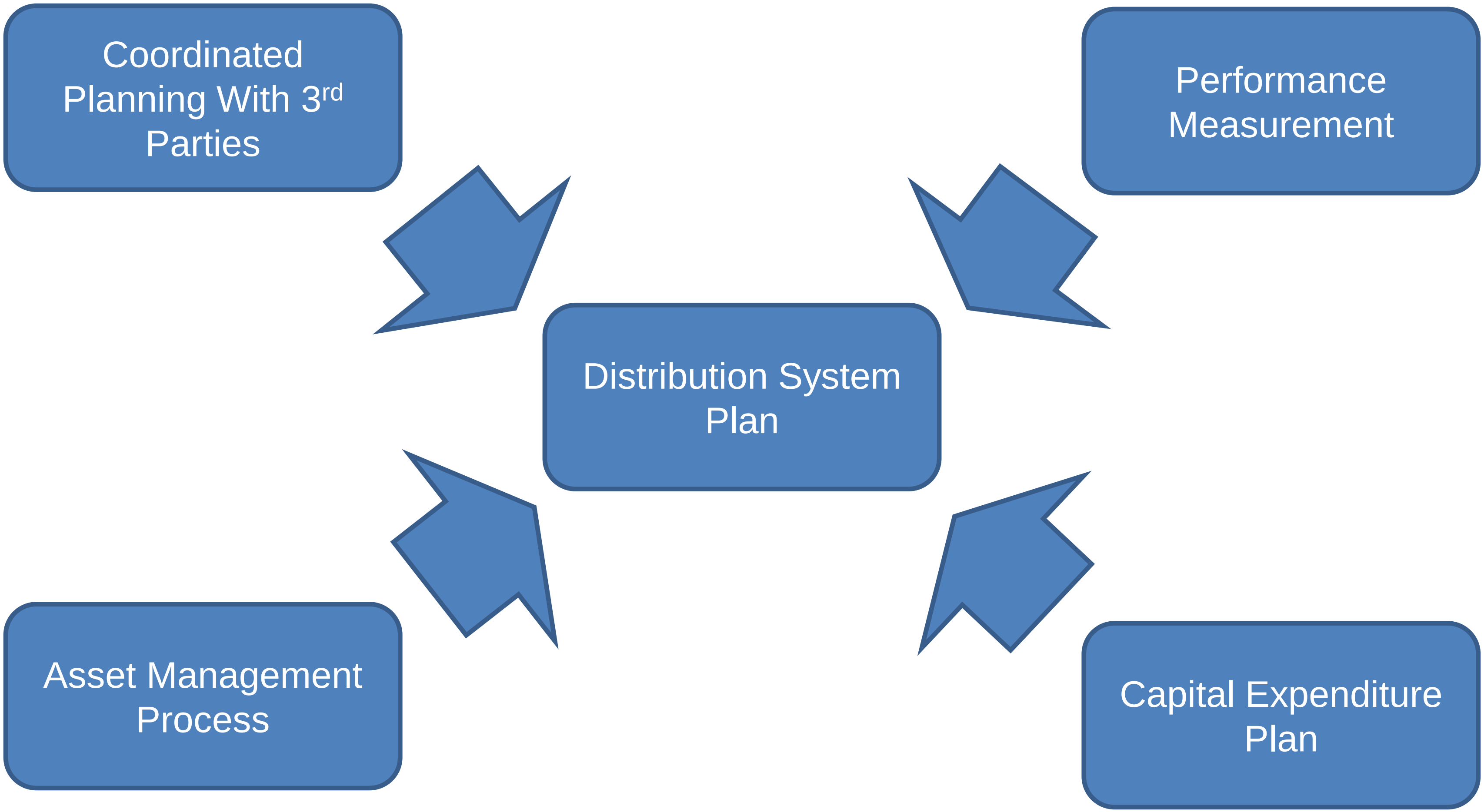
How is the Distribution System Plan evaluated?

- Is it consolidated?
- Clear process in developing an optimized plan
- Does it align with customer preference?
- Quantifiable benefits for customers?
- Support achievement of performance outcomes
- Controlled cost through optimization, prioritization, and pacing?
- Integrated conservation, REG, regional plan, smart grid, and public policies

Performance Outcomes

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance
- Other LDC specific outcomes as appropriate

Distribution System Plan



Coordinated Planning

Distribution System Plan ← Coordinated Planning With 3rd Parties

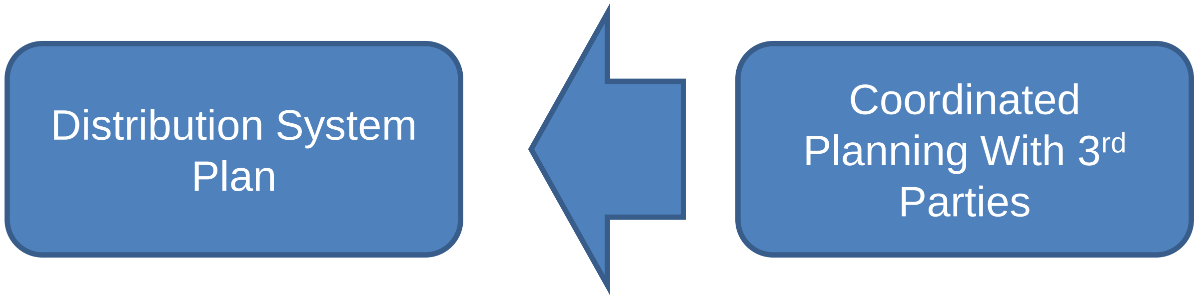
Consultation Components

- Purpose?
- Distributor initiated or invited?
- Other participants?
- Nature and timing of deliverable
- How the consultation affected the DS Plan

Examples

- Regional Planning Process and customer consultation

Coordinated Planning



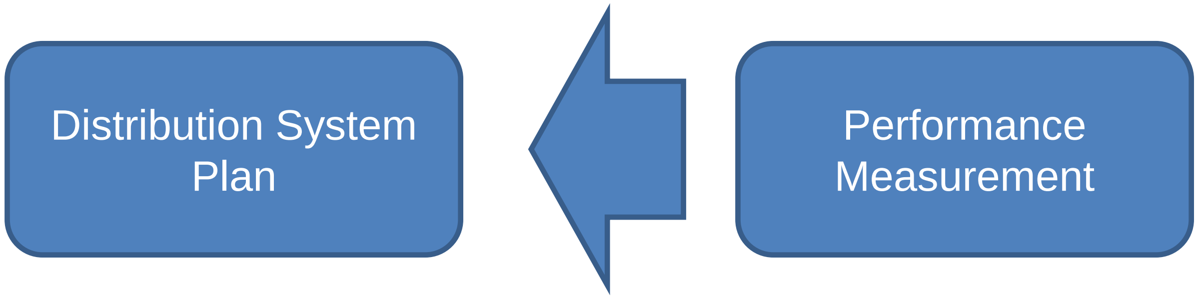
Successes

- Utilities have included different methods used to gather customer input

Area of Improvement

- Customer consultation is not a satisfaction survey

Performance Measurement



Performance Measurement Components

- Identify performance metrics
- Performance trend
- How performance trend affected DS Plan

Examples

- Reliability
- Power quality
- Actual vs. planned costs

Asset Management Process

Process Overview

- Relationship between asset management objectives and corporate goals
- Asset management objective prioritization
- Asset information
- Input/output to the process

Asset Management Process

Distribution System Plan

Asset Management Process

Overview of Assets Managed

Assets Managed

- Distribution service area overview
- System configuration
- Asset profile
- Asset capacity in relation to planning

Asset Management Process

Successes

- Most LDCs are utilizing some kind of asset registry
- Some LDCs are doing extensive condition assessments

Area of Improvement

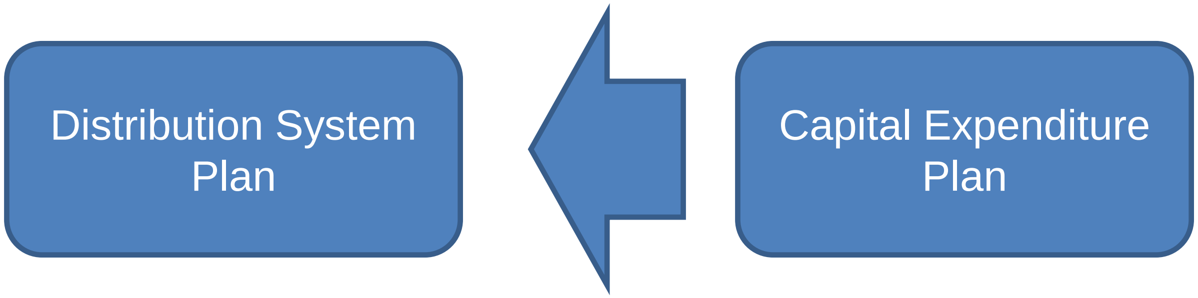
- Asset age alone is not a strong metric for asset management
- Provide clear link of asset condition plan and proposed capital expenditures

Asset Management Process

Policies and Practices

- Replacement and refurbishment
  - Maintenance planning criteria
  - Preventative inspection
- Asset life cycle risk management
  - Risk assessment
  - Select and prioritize capital expenditures
  - Mitigation methods

Capital Expenditure Plan



Capital Expenditure Plan Components

- Summary
- Process Overview
- System assessment for renewable generation
- Capital expenditure summary
- Justifying capital expenditures

Capital Expenditure Plan

Key information

- Capability to connect new load/generation
- Annual capital expenditure
- Capital allocation among categories
- List of material capital expenditures by category
- Regional planning
- Customer engagement
- System development

Capital Expenditure Plan

Process Overview

- Planning objectives
- Alternative system relief
- Tools and methods
- Customer engagement

Capital Expenditure Plan

Successes

- Utilities have utilized a systematic approach to investment planning

Area of Improvement

- Stronger investment selection algorithm (e.g. risk mitigated per dollar spent)

Capital Expenditure Plan

Key information

- List of existing renewable generators
- Expected projects
- System capacity
- Constraints

Capital Expenditure Plan

Project Categories

- System Access
- System Renewal
- System Service
- General Plant

Capital Expenditure Plan

Distribution System Plan ← Capital Expenditure Plan ← Capital Expenditure Summary

Investment Details

- How does the investment meet goals?
- Alternatives (consider CDM)
- Prioritization
- Pacing of continuous projects
- Capital and O&M trade-off
- How does it align with performance outcomes

Capital Expenditure Plan

Area of Improvement

- Alternative
- Greater consideration of capital to OM&A trade-off
- Project prioritization method not specific
- Performance level tracking
- Project benefits need to be quantified
- Robust link between customer engagement and projects

Capital Expenditure Plan

Material Project Evaluation

- Efficiency, Customer Value, Reliability
- Safety
- Cyber-security, Privacy
- Co-ordination, Interoperability
- Economic Development
- Environmental Benefits

Capital Expenditure Plan

Good LDC examples

- Horizon Utilities
  - Through description of existing distribution system
  - Comprehensive asset management process
  - Asset registry and use of health index
  - Project prioritization process
- Entegrus
  - Customer feedback tied to request in OM&A and DSP
  - Specific projects address customer concerns with a quantified measure

Thank You

QUESTIONS?

Ratepayers' Perspective

2017 OEB's Orientation Session for Electricity Distributors Rebasing

Mark Rubenstein –*Co-counsel to the School Energy Coalition*

Shepherd Rubenstein

School Energy Coalition

- Who are we?
  - Coalition of seven school board organizations
  - All school boards are active members
  - 5000 schools with 2 million students
  - Spend $500 million per year on energy
  - Details posted on the Board's website
- Intervention Principles
  - Always look for the win-win solution
  - Think long term
  - "Walk softly but carry a big stick"

Electricity Ratepayer Groups

- Active ratepayer groups in LDC applications:
  - Almost Always – VECC and SEC
  - Often – AMPCO, CCC, Energy Probe, and BOMA
- Intervenor Representatives: Experienced lawyers and consultants
- Division of responsibilities

Why are we all here

- Regulation as a substitute for competition – Board as market proxy
- Each ratepayer group represents a segments of your customer population
- To review, probe, and test the reasonableness of your application
- To act as the counterweight - the Board needs other perspectives on your application.

Preliminary Work

- Local newspaper, presentations to shareholders (city councils), google searches, your website, etc.
- Yearbook data for all years
- Building our own comprehensive database
- Previous applications, results, rates
- People: Who do we know?
- Customer meetings/feedback

What we hope to see in your application

- A detailed explanation of your planning process
  - Regulatory application and process, should be intertwined with your business planning process, not separate processes
  - Show us where benchmarking and comparative data enter into your planning process
  - How do you consider customer preferences and rates impacts. Show us trade-offs.
- Explain to us the challenges your LDC is facing
  - Show investigation and analysis
  - Thoughtful plan to deal with them
- Metrics and targets
- Show us the value for money of your proposed investments
  - Demonstrate why the investment is worth the added cost

How do we review an application

- Planning Documents
  - Strategic/business plan, shareholders' agreement/direction, budget guidance documents
  - Financial statements, rating agency reports
  - Distribution System Plan, Asset Condition Assessment
  - Comparative data and benchmarking
  - Rates and revenue requirement trends
  - Past applications. Have you done what you said you were going to do?
- Projects and programs
  - Business cases (Capital and OM&A)
  - Third-party reports and analysis
  - Variance analysis, expense trends, Chapter 2 Appendices
  - Benchmarking
  - Individual issues – what are they and what is your plan
- The nitty-gritty
  - Continuity schedules, depreciation, revenues (load forecast and offsets), PILS, cost allocation and rate design, D&V accounts, accounting issues

Comparative Data

- Valuable diagnostic tools
  - Identify potential problem areas
  - Test against evidence for consistency
  - “Outcomes-based” analysis
- Comparative Rates are very important
  - Captures all aspects of costs, but not granular enough
  - Doesn’t always account for type of service territory and customer mix
- Rate Base and Capital Spending
  - e.g. Capital Additions/depreciation ratio, unit costs trends, ACA analytics

Comparative Data

- OM&A Metrics
  - e.g. OM&A or FTE per customer, unit cost trends, compensation information
- Other Metrics
  - Components of revenue (e.g. by class)
  - Debt/equity ratio (leveraging)
  - Rates
- We have been building our own comprehensive database of comparative data using past case information and yearbook information

Consistent Issues

- RRFE
  - Outcome focus – Metrics and targets
  - Value for money
  - Benchmarking
  - Robust capital planning requirements
    - Age versus condition of assets
  - Customer Engagement – rates versus reliability
- Customer growth or decline
- Past underinvestment
- Aging workforce

Interrogatories

- “The purpose of the interrogatory process is to test the evidence”
  - Filing Requirements For Electricity Distribution Rate Applications
- What we are looking for?
  - Documents referred to (or omitted), sometimes prior versions
  - Explanations
  - Missing data, steps, or confusion
  - Comparative data
  - Scenarios, “stretch testing” the assumptions and numbers
- If you do not understand the question or cannot provide the information we have asked for, pick up the phone or email

Technical Conferences/Clarification Questions

- Technical Conference
  - The Board is generally not scheduling them anymore for non-Custom IR cases
  - Usually first contact with intervenors
  - Not cross-examination, but tougher than interrogatories
  - Model technical conference is a dialogue
  - Point is to save the Board panel from wasting their time
  - Allows for parties to correct the smaller issues
- Clarification Questions
  - Provided to LDC a few days before settlement conference
  - Clarifying outstanding important issues that are required for settlement
  - Expectation is the answers are put on the record

Settlement Conferences

- Process
  - Exchange of information/dialogue
  - Intervenor caucus
  - Offers back and forth
  - Documenting any agreement
- Offers
  - Issue by issue– revenue requirement and revenue forecast usually first
  - Deficiency based packages (looking for savings)
- Settlement of other issues
  - Asset management plan and longer term issues
  - Metrics and targets
  - Cost allocation and rate design
  - Deferral and variance accounts

Settlement Conferences

- Ratepayer group point of view
  - Result by agreement vs. result by decision
  - Settlement Conference positions vs. hearing/argument positions
  - Comparative data increasingly influential
  - Uncertainty about the interpretation and application of Board policies and principles
- How to get there
  - Willingness to compromise/listen – on both sides
  - Hearings can lead to rough justice, settlements allow for creative solutions
  - Achieve a known result versus the unknown of a Board decision

Oral Hearings

- Pre-Oral Hearing Questions
  - Technical or data heavy questions provided in advance to limited undertaking requests and bogging hearing down unnecessarily
- Cross-examination
  - Bias in favour of the cross-examiner
  - Good questioners are well prepared
  - We want to challenge the assumptions in the application
  - The real testing of the evidence
- Approach
  - Don’t “play the game” - use your natural advantage
  - Credibility not easily lost, but also not easily regained
  - Pay close attention to questions from Board members

The Future

- Board working on a new consumer engagement framework – *Giving Ontario Energy Consumers a Stronger Voice*
- Community Days – how does the feedback enter into the Board's decision process
- Hearings in the communities
- Regional Consumer Representatives – potential piloting to begin in 2017 or 2018

Thank you

Mark Rubenstein – Shepherd Rubenstein

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Shepherd Rubenstein

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

2018 Cost of Service Filers – Orientation Session

Appendices and Models

- Including Cost Allocation and Load Forecasting

Keith C. Ritchie

July 25, 2017

First Up …

Models

Evolution of the Appendices and Models

- Every year, changes to the Excel-based spreadsheets – Chapter 2 appendices, models, workforms – to align with:
  - Changes in Legislation
  - Changed or new OEB policies, handbooks, reports, guidelines or Codes
  - Changes to the Filing Requirements
    - Primarily Chapter 2 for CoS filers
  - Changes in accounting or tax rules
  - Learnings from processing applications
  - Changes in informational needs
- Consistency in data presentation facilitates easier and quicker review of many applications by OEB panels, staff, stakeholders
- At the same time, we try to balance the need for information versus the amount of data and the effort to collect and input it

Changes to Chapter 2 Appendices

- For 2018, the number of sheets reduced to 38:
  - 2-Cx (Depreciation/Amortization) schedules reduced to one sheet, to be used for all historical and forecast years
  - 2-KA eliminated with issuance of OEB policy on Pension & OPEBs
- This follows additions and deletions in 2017:
  - 2-A List of Requested Approvals
  - 2-IA (Instructions on Load Forecasting Analysis)
  - 2-IB is an expanded Load Forecasting summary and analysis that replaces the previous 2-IA
  - 2-P (Cost Allocation), 2-PA (Residential Rate Design), 2-V (Revenue Reconciliation) moved to RRWF
- 2-L (OM&A per customer and per FTE) expanded to separately disaggregate O&M and Admin expenses
- Most other sheets have had minor formatting and other changes
  - Improve use, inputs and presentation, but do not materially affect calculations

Changes to Other Models

- Cost Allocation
  - Added some “sanity checks” (i.e., NCP4 <= NCP)
- DVA (Continuity Schedule) Workform
  - Update for changes in DVAs
- LRAMVA Workform
  - Introduced in 2017, and altered for 2018
- PILs
  - Updated for 2018 tax rates and changes
- RTSR
  - No material change from last year; will be updated when 2017 UTRs issued
- Tariff Schedule and Bill Impacts
  - New Model, introduced in 2016 for 2017 CoS, and based on IRM model
  - Replaces Appendices 2-Z and 2-W
- RRWF
  - New version in 2017 that adds load forecast, cost allocation and rate design elements
  - Appendices 2-P, 2-PA and 2-V integrated into the RRWF

Capital Funding Module (for ACM/ICM)

- New version issued in February 2016 following issuance of Capital Funding Options Supplemental Report on January 22, 2016
- Model incorporates new Materiality Threshold calculation and is used for ACM applications in CoS applications and for ICM and ACM rate rider applications in Price Cap IR applications
- Updated for 2018 test year range, but no other changes to methodology

Tariff Schedule and Bill Impacts

- Separate model to generate the current and proposed Tariff Schedule and subsequently the Bill Impacts
- Replaces Appendices 2-Z and 2-W
- Follows the format in the IRM model
    - Tariff generated first, and then bill impacts generated based on current and proposed rates.
- Excel version of the Tariff of Rates and Charges
    - While the IRM version populates the Tariff Schedule from rates already entered in or calculated in that model, the utility will have to enter its proposed tariffs. Current rates populated from rates database.

RRWF

- Improves the utility of the RRWF to go beyond just calculating and verifying the revenue requirement
- Link the revenue requirement to load forecast, cost allocation and rate design information for the test year to:
  - Generate distribution rates
  - Perform revenue reconciliation with the revenue requirement

RRWF Changes

- Sheets 1-9 largely unchanged
- New table on Sheet 9 summarizes Service and Base revenue requirements and the associated sufficiency/deficiency calculations
- Added Sheets 10-13
  - Sheet 10 – Summary of customer and load forecast
  - Sheet 11 – Cost Allocation
    - Previously Appendix 2-P
  - Sheet 12 – Residential Rate Design
    - Previously Appendix 2-PA
  - Sheet 13 – Rate Design and Revenue Reconciliation
    - Previously Appendix 2-V
- “Summary of Key Changes” now becomes sheet 14

Why the need for change?

- The RRWF serves as a summary of the cost of service application:
  - During the processing of the application, from initial application to Decision/DRO, summarizes the key changes in the components of the revenue requirement
  - Allows parties to better estimate rate impacts during processing
  - After completion of the application, it is a historical summary of the key data from the application.

Caveats

- The RRWF, even as a rate generator, does not replace the rate generator and other models that utilities use for their applications.
- It is dependent on the outputs of load forecast, cost allocation, PILs and other models that an applicant uses.
- The RRWF, just like the other models you may use, is very dependent on the input data:
  - Be consistent in the data used, with respect to whether numbers are rounded or not
  - Keep the data updated.

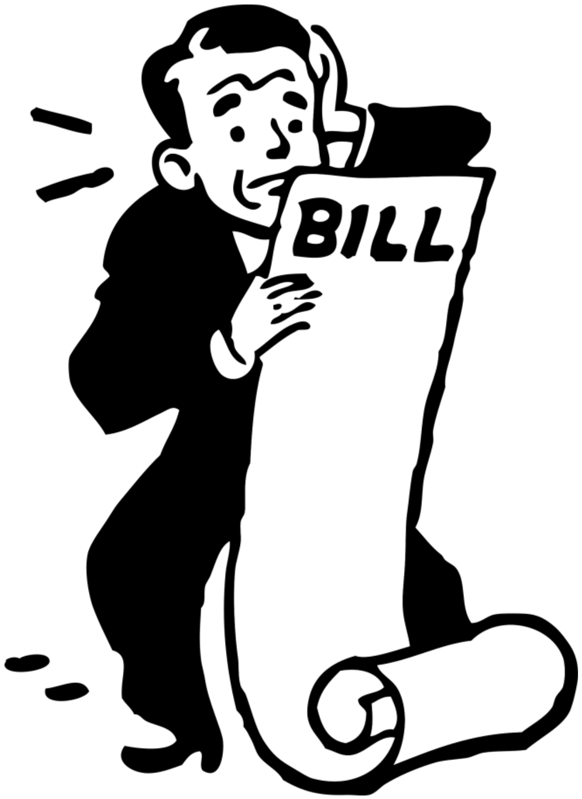
Parting Remarks on the models

- Models are designed to be flexible and accommodate most situations, but it is not possible to contemplate every utility's circumstances
- Many models and sheets are unlocked, but where they are locked, it is for a reason:
  - Preserve integrity of model calculations
  - Proper operation of a model, particularly if macro-driven, may depend on structure
- Staff will try to assist, but availability is subject to time and resources

Next up …

Cost Allocation and Rate Design

- Who is picking up the bill?



Cost Allocation Policy: Your Last Filing (2013)

- OEB had recently issued Report of the Board: "Review of Electricity Distribution Cost Allocation Policy", EB-2010-0219, March 31, 2011

- Cost Allocation Model was updated to implement:
  - MicroFIT administrative costs worksheet
  - Miscellaneous Revenues allocated in proportion as corresponding cost drivers
  - Distributor-specific weighting factors for Services and Billing
  - Treatment of transformer ownership allowance reflected in CA model
  - Revenue to Cost Ratio ranges narrowed (GS 50-4,999, Sentinel Lighting)

- July 16, 2013 memo addressed allocation by host to embedded distributors
  - If host distributor has a separate embedded class, continue to show a separate line in CA model and Appendix 2-P.
  - If host distributor bills embedded distributors in GS class, host must must complete appendix 2-Q. Embedded distributors should be included in data inputs for GS class (customer count, load forecast, revenue, etc.)

- Deferred for study and future development:
  - Unmetered Loads (EB-2012-0383; Board report Dec. 2013)
  - Load Displacement Generation (EB-2013-0004)

CA Policy Review: Unmetered Loads (EB-2012-0383)

OEB Report issued December 19, 2013

- “Updated kW and kWh data should be used to update load profile date for the purpose of the distributor’s next cost allocation filing with the Board…”, i.e. next COS

- “Conditions of Service should set out in reasonable detail how unmetered load customers are to file updated data with their distributors…”

- “Board expects distributors to assist unmetered load customers with understanding the regulatory context in which distributors operate…”

- “Board will include instructions or worksheets for the cost allocation model definitions for account, connection, customer, and device (as they related to unmetered loads)…”

CA Policy Review: Unmetered Loads (EB-2012-0383)

Notice of Amendment to a Code, issued May 15, 2014:

- Section 2.4.6 of the Distribution System re: unmetered customers
- Took effect Jan. 1, 2015

s. 2.4.6:

- The following items in relation to unmetered load customers:
  - the **rights and obligations** an unmetered load customer has with respect to the distributor and the rights and obligations a distributor has with respect to an unmetered load customer;
  - the **process** an unmetered load customer must use **to** file its **update**d **data** with its distributor and what evidence is necessary for the distributor to validate the data;
  - the **process** the distributor will use to **update the bills** for an unmetered load customer; and
  - the **process** the distributor will use to **communicate and engage** with **unmetered load customers** in relation to the <u>preparation of cost allocation studies, load profile studies or other rate-related materials</u> that may <u>materially impact</u> unmetered load customers.

CA Policy Review: Street Lighting (EB-2012-0383)

OEB issued letter on June 12, 2015 outlined new cost allocation policy for street lighting rate class:

- Adopted recommendations from Navigant study, *Cost Allocation to Different Types of Street Lighting Configurations*

- Primary and Line Transformer assets to be allocated using street lighting adjustment factor (SLAF):

$$SLAF = \left(\frac{Residential\ NCP4}{\#\ of\ Residential\ Customers}\right) \Big/ \left(\frac{Street\ Light\ NCP4}{Number\ of\ Devices}\right)$$

- The “adjusted connections” is then used in place of the actual number of connections for the CCP and CCLT allocators:

$$Adjusted\ Connections = \frac{Number\ of\ Devices}{SLAF}$$

- Secondary assets will continue to use the number of connections as the allocator
- Street Lighting R/C ratio range tightened.

Load Displacement Generation (EB-2013-0004)

- OEB initiated consultation to develop standby rates for Load Displacement Generation

- In a letter dated June 11, 2015, the consultation was concluded
  - OEB Rate Design Report, issued April 2, 2015, indicated that the OEB intends to remove the standby rate when the new rate design policy implemented for commercial customers
  - New commercial customer rate design to be developed through a separate consultation process
  - Until then, the existing policy regarding standby rates remains unchanged:
    - Distributors may apply for standby charges on a final basis. Must be supported by evidence. <u>Affected customers must be notified of proposed changes.</u>

Policy Impacts on Filings: Summary

- Host distributors without a separate embedded distributor class must complete Appendix 2-Q
- Distributor should confirm adoption of code amendments to conditions of service in evidence
  - Highlight sections that have changed
- Exhibit 7 should explain how demand data in CA study reflects most recent data obtained from unmetered customers through engagement prior to filing
- Distributors must provide both device and connection data in cost allocation model
  - If both inputs have not been previously provided, provide explanation on how numbers were derived/confirmed
- Tighter Revenue-to-cost ratio range for street lighting class

Cost Allocation Filings: 2013-2018

- **Exhibit 7, then and now:**
  - Summary description, highlighting rebalancing (if any)
  - Similar to 2013
  - If using load profiles from Hydro One informational filing, distributor must explain why it has not updated its load profile and confirm, with discussion, how it intends to update its load profiles for its next COS application.

- **RRWF – Sheet 11**
  - Provides summary tables for results of cost allocation study and proposed changes/rebalancing
  - Used to be Appendix 2-P, no change in required information

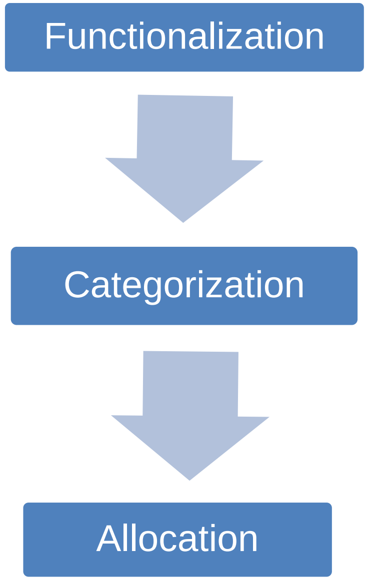
- **Appendix 2-Q**
  - Information required of host distributor, if no separate class of embedded distributor(s)
  - Provides sharper focus on embedded distributor(s) than CA Model

- **CA Model, then and now**
  - Similar to V3 (2013)
  - Incorporates policy changes as a result of
    EB-2010-0219 and EB-2012-0383
  - Includes more instructions reflecting experience in other applications
  - For 2018, "sanity checks" to highlight invalid data and situations

Cost Allocation Framework

Conceptual Framework unchanged

- 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 (min. 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



Cost Allocation Models: Version summaries

Yr.	V.	Key Changes

2014	3.1	• Updated list of accounts in worksheet I-3 “Trial Balance”
		    • Removed formulae for PP&E balance
		    • Recovery of Account 1576/1576 balances per June 25, 2013 memo
		• Direct Allocation – provide for inclusion of overhead costs
		• Clearer instructions, particular with respect to weighting factors

2015	3.2	• Additional instructions – Sheets I4 (Asset Break-out) and I6.1 (Revenue) • Correction in Cell C148 of sheet I9 (Direct Allocation) for calculation of cost of capital and associated taxes/PILs on NBV of directed allocated costs

2016	3.3	• Street Lighting class cost allocation per new OEB policy
		    • Street Lighting Adjustment Factor (SLAF) calculated on sheet I6.2. Cells J22 and J23 divide number of devices by the SLAF for allocation of primary and secondary transformer assets
		    • On sheet E3, formulae for CCP and CCLT takes values calculated on I6.2 for SL class
		    • On sheet I2, Residential, GS < 50 kW and SL classes are locked for proper calculation of SLAF
		    • LDC must include both device and connection data. If not used in previous CA studies, applicant should describe how number of devices and connections were derived/verified

2017	3.4	• Instructions updated, including removal of outdated instructions
2018	3.5	• “Sanity checks” – to ensure that anomalous situations are identified (e.g. NCP4 <= 4 x NCP)

Intangible Asset Accounts

USoA Account		Equivalent Account in Cost Allocation Model	
1609	Capital Contributions Paid	1810*	Leasehold Improvements
1611	Computer Software	1925	Computer Software
1612	Land Rights	1806	Land Rights

* or other unused 1800 series account with DCP/TCP allocator (e.g. 1825)

Rate Rebalancing (RRWF – Sheet 11)

- Applicant must complete Sheet 11 of RRWF:
    1. Approved revenue-to-cost ratios
    2. Status quo ratios
    3. Proposed ratios

- Policy 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

Residential Rate Design: Background

- OEB Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) was issued on April 2, 2015
  - All distributors would transition to a fully fixed charge for the residential class using a standard method
  - Transition over 4 year period in equal increments beginning for 2016
  - Exceptions to standard method to be considered where:
    1. Fixed charge increases by more than $4
    2. Where the combined impact with other changes in a rate application would lead to “unusual rate impacts”

- OEB issued letter on July 16, 2015, providing implementation details for new rate design
  - Details also reflected in Filing Requirements and models

Rate Design Filing Details

- Method for calculation of fixed rate is now included in RRWF (sheet 12)
  - For COS: Calculation based on billing determinants from proposed load forecast
- All new distribution-specific riders should be fixed-only for residential class
  - e.g., Group 2 DVAs, disposition of Account 1575/1576
  - Rate riders arising from variances in pass-through charges that are part of delivery line (such as wholesale market service rate) should continue to be collected and disposed on variable basis
  - Existing rate riders that have not expired should remain unchanged
- No changes to method for LRAM/LRAMVA calculations
- Identical treatment must be applied for any seasonal residential classes
- Expect that most distributors will maintain transition period approved in 2016 rate application as the default
- Filing should show results of both mitigation tests

Approach to Mitigation

If either of two tests for mitigation is met, distributor should propose mitigation for the residential class.

First scenario: If the rate design change itself causes the fixed charge to increase by more than $4 in a particular rate year

Mitigation Approach:

- Allow an extra transition year as standard form of Type 1 mitigation
- Require LDC to propose mitigation strategy if this does not address the problem
- One extra year should address most distributors
- Allows flexibility for the few remaining exceptions

Second Scenario: Evaluate overall bill impacts using distributor-specific low-volume customer

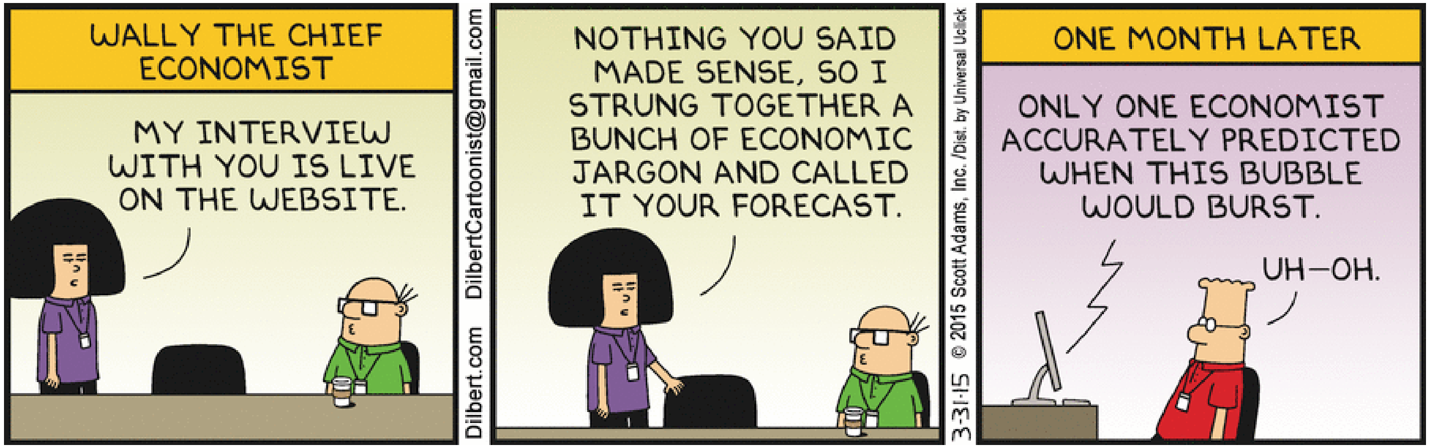
- Using standard 10% total bill impact test, apply test to a low-volume customer at the lowest 10th percentile of consumption (to a minimum of 50 kWh). Therefore, mitigation treatment tailored to those customers whose bills increase the most

Mitigation Approach: Distributor must file mitigation plan for entire residential class or indicate why such a plan is not required

- Mitigation tool is at LDC’s discretion.
- More mitigation tools available to distributor to address this type of mitigation (e.g. disposition period for DVAs)

Finally ...

Load Forecasting



Role of Load Forecasting in Cost of Service Applications

- Establish the sales volumes for the test period:
  - Number of customers
  - Consumption of customers (kWh)
  - (Peak) Demand of customers (kW or kVA)
- Used in several ways:
  - Allocators for recovery of costs from different customer classes
  - Billing determinants for determining fixed and variable rates and for other rate riders and adders
  - Sales volumes (customers, kWh, kW) factors into revenue sufficiency/deficiency
- Load forecast important for capital planning for system reliability and capacity
  - Different purposes and values between system capacity planning and for rate setting (i.e., extreme values and probability of failure versus expected weather-normalized load), but models should be related

Forecasting Number of Customers / Connections

- 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 (geometric mean), by customer class
  - Most utilities (and the communities they serve) have stable growth rates of about 0% to 2% per annum
- Adjustments may be made for unique growth patterns in individual classes, movement between classes, or changes in customer class definitions
- New customer classes need to be supported

Forecasting Demand and Consumption

- Utilities generally forecast purchased consumption (kWh)
  - Purchases available monthly from IESO bills; customer billed demand often not available for a calendar month due to billing cycles
    - TOU data provides for calendar monthly data, but will need several years to collect sufficient data.
- 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
- Differing Modelling approaches
  - Normalized Annualized Consumption
  - Regression
  - Others
- Beginning in 2013 CoS, several utilities used class-specific models for: Residential, GS < 50 kW, GS > 50 kW
  - Other classes forecasted using NAC or similar methods

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 and persistent impacts of CDM programs	-ve
Other Variables?		
e.g., August 2003 Blackout, 2013 Ice Storm	Binary flag variables for blackout or reduced consumption due to storm damage. As needed – but should be explainable as linking to identifiable and material phenomena	-ve

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?
  - e.g., +ve CDM, -ve Income, -ve HDD or CDD are unintuitive
- Use of binary variables?
  - Binary variables can eliminate impact of outlier data points …
  - … but, overused, may hide other issues with model specifications
- 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

2.3.2 – Load Forecast Variance Analysis

- Check on the accuracy of the distributor's past load forecasts
- Variance analysis for customers/connections, kWh, kW, revenues, kWh per customer or connection for 5 historical years, and Bridge and Test Years:
  - Historical OEB-Approved vs. historical actuals
  - Historical OEB-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
- Appendix 2-IB must be filled out
- Sheet 9 of the RRWF must also be filled out with the test year load forecast (Initial Application, during processing, and per Board Decision)

Conservation and Demand Management – Relationship with Load Forecasting

- Since 2006, distributors have been delivering CDM programs
  - Distributor, OEB-approved or IESO programs
  - Four-year CDM framework (2011-2014)
  - Current six-year CDM framework (2015-2020)
- Successful CDM reduces load relative to historical levels and relative to customer growth, and should have persistence into future periods.
- CDM results reported by IESO
  - Reported kWh results are annualized (i.e., full year) impacts
    - Used for CDM targets and LRAMVA
    - Since programs in a year are rolled out throughout the year, first year impact will be less
      - Half-year for first year impact
      - Full-year impact for persistence in subsequent years
- Utility should account for impacts of CDM programs in all years up to the test year
  - Issue is the accuracy of bridge and test year forecasts, trending from historical actuals and/or reflecting CDM initiatives to meet CDM targets
  - Impacts and persistence of then-current CDM programs reflected in historical actuals …
  - … but need to also estimate impacts of new CDM programs in bridge and test year forecasts

LRAMVA

- LRAMVA
  - New CDM Guidelines issued April 2012
  - In December 2014, the OEB confirmed the continued use of the LRAMVA for the 2015 to 2020 CDM Framework
  - Threshold for LRAMVA in test year will be related to the CDM adjustment that is factored into the load forecast in the cost of service test year
- CDM impacts measured by IESO, or a third party in accordance with IESO guidelines
- For 2018, the OEB must approve:
  - 2018 test year load forecast, including the persistence of historical programs up to 2016, and expected 2017 and 2018 CDM programs impacts on the 2018 consumption and demand
  - Corresponding amounts used for establishing the 2018 LRAMVA threshold by class

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 IESO-reported numbers for persistence of CDM programs on the test year load forecast
- CDM adjustment on load forecast must recognize the following:
  - “Real” 2018 CDM program impact on 2018 demand is less than annualized (½ year rule used as default)
  - Historical CDM program impacts are captured, in some form, in historical actuals up to 2016
  - 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 IESO
- Appendix 2-I updated for 2018 Filers
  - Only 2015-2020 table to be filled out
- New LRAMVA model to be completed
  - Relates to Account 1568 entries and disposition

Questions?

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Forecasting using the OEB Cost Benchmarking Model

Jane Scott

July 25, 2017

Overview of Forecasting Capabilities

- The OEB has requested that LDCs filing for new rates provide information on cost benchmarking as a standard part of the filing.
- The OEB currently uses a cost benchmarking model to determine if changes in cost performance warrant changes in the stretch factors established as part of IRM
- It is possible to use forecasted test year data to calculate the cost performance consistent with proposed OM&A and capital expenditures.
- Benchmarking proposed costs will provide an additional indicator of the direction of cost performance
- This work also provides LDCs with a method to demonstrate that their proposal will maintain or improve current cost performance

How Benchmarking Works

- Cost benchmarking involves calculating the following:
  - An “actual” total cost consistent with the benchmarking definition
  - A predicted total cost using forecasted business conditions
- Cost performance is defined as the difference between actual and predicted cost
- The Forecasting worksheet of the Enhanced Benchmarking model contains the relevant historical information and a place to enter forecasted values. These inputs allow for the calculation of actual and predicted cost for future years.

The Benchmarking Forecast Model

- The forecast worksheet has been separated from the larger benchmarking calculations workbook
- A worksheet for LDC data inputs will be added with the following
  - 2016 historical values
  - Columns for 2018 test year data and 201
  - 7 “bridge” year data
  - Columns for 2018-2022 data for those filing custom IR proposals
- Advanced users may wish to learn more about how the model calculates actual and predicted cost.
- No action by the LDCs is required on the second and third worksheets

Data Requirements

- Eleven data items are required:
  - OM&A expenses as adjusted
  - Gross plant additions and HV plant additions
  - Customers, Delivery Volumes, and Peak Demand
  - Circuit-km of line
  - Ten-year customer growth
  - Rate of return, labor price, and economy-wide inflation forecasts
- There are three worksheets that comprise the Benchmark Forecast Model. The next 3 slides provide a quick overview of each.

Worksheet 1: Model Inputs

- The 11 required data series are numbered on this worksheet
- For those with standard filings, data need only be provided up to the 2018 test year
- For those proposing custom IR, the model has the capability to go out to 2022
- The OM&A calculation is more involved and two options are offered
  - Method 1: The LDC calculates the total OM&A of accounts used for benchmarking, HV OM&A, and the LV adjustment and enters the values. Support for these calculations shall be provided.
  - Method 2: The applicable OM&A account data are entered and the LV adjustment data are provided. The spreadsheet calculates OM&A cost.

Worksheet 2: Benchmarking Calculations

- These calculations are taken from the Enhanced Benchmarking Spreadsheet Model.
- The information provided on the Model Inputs worksheet feed into this worksheet. No LDC action is required.
- Additional information on these calculations are included as part of the Spreadsheet Model. A users guide is available for those that wish to learn more about how the model works.
- There was a training session on May 22, 2015 on Benchmarking. The materials are posted on the OEB website.

Worksheet 3: Results

- The results worksheet takes the benchmarking results from the calculations worksheet and presents them in a cleaner format
- It presents the actual and predicted cost as calculated by the model
- The method the model uses to calculate percentage differences uses logarithms. In most cases these will be similar to the familiar arithmetic method.
- The first line of cohort information refers to where an individual year's performance fits within the Board-established categories used to determine stretch factors.
- The second line refers to the three-year average performance used to assign stretch factors
- No LDC action is required on this worksheet

OM&A Expense Calculations

- The OM&A cost calculation is specific to benchmarking
- The included accounts are listed on the worksheet
- Some costs are not included in the total or explicitly excluded:
  - Bad Debt is not included
  - Generation or Transmission OM&A accounts are not included
  - High voltage costs classified as distribution are excluded (the HV adjustment)
- Some costs associated with LV service from Hydro One Networks are added
  - 100% of the following are added
    - LVDS Low Facility Charge
    - Specific ST Lines Facility Charge
    - Meter Charge
  - 45% of HVDS Low Facility Charge is added
- These steps were taken to improve comparability among LDCs

Capital Cost Calculations

- The capital cost calculations are complex, but only data on plant additions are required from the LDC to update the model
- The gross capital additions should <u>not</u> be reduced by contributions
- Depreciation is standardized across LDCs
- Plant additions are separated into quantity and price each year.
- A "perpetual inventory" method is used to track the <u>quantity</u> of plant added and removed each year.
- A capital price is multiplied by the capital quantity to get a measure of capital cost
- This capital cost will <u>not</u> be the same as calculated using traditional cost of service methods

Caveats

- The prediction the model produces must be compared to the LDC cost calculated using the same methodology. The spreadsheet does this calculation.
- The model is designed to produce a valid comparison between actual and predicted cost for a given LDC for a given year. Comparisons of predicted cost to other data such as the historic cost of other LDCs may not be valid.
- A direct comparison of an LDC revenue requirement to the model prediction would not be valid. Reasons for this include:
  - Certain costs are excluded from the benchmarking cost calculations
  - The capital cost used for benchmarking purposes is different than that used for ratemaking
    - Taxes are excluded
    - Depreciation rates are standardized and are not straight-line
    - The concept of rate base is not used in the calculations

Additional Resources

- Training Session Materials
- The Users Guide for the Benchmarking Model
- 2017 EDR Benchmarking Spreadsheet Forecast Model

It may be necessary to right-click the above links and select "open hyperlink" to access the file on the OEB website

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CoS Filing Requirements

Lost Revenue Adjustment Mechanism

Josh Wasylyk

July 25, 2017

LRAMVA Work Form

- OEB’s LRAMVA work form has been refined for 2018 rate applications
- LRAMVA Work Form must be used by LDCs filing both IRM and COS applications
- LRAMVA Work Form builds on best practices and establishes a consistent approach for all LDCs

Purpose and Overview

- Use of a common tool to report information and calculate CDM impacts
- Consolidates information that LDCs have received, and will continue to receive, from the IESO
- Allows for flexibility in changes to the form, as appropriate, to reflect the LDC’s circumstances

Policy Changes and Requirements

LRAMVA Calculation

- There are no changes to how LRAMVA values are calculated:

(Final Net CDM Savings – Load Forecast CDM Component) x Distribution Volumetric Rate = LRAMVA

Demand Savings

- OEB held a consultation with LDCs and other expert stakeholders in early 2016 to determine any policy changes related to demand savings from CDM programs (EB-2016-0182)
- OEB determined new policy related to eligible demand savings from energy efficiency programs are specified in Table 1 the OEB Report "Updated Policy for Including Peak Demand Savings in LRAMVA Calculation"
- The new LRAMVA work form incorporates the new policy:
  - Indicates the number of months peak demand savings are applicable within from energy efficiency programs
  - Excludes demand savings from Demand Response programs
- DR3 savings should generally not be included in the LRAM savings unless supported by empirical evidence to be reviewed in a COS application

LRAMVA Work Form (Version 2)

- Updates to the LRAMVA workform for the 2018 rate applications include:
  - Enable LDCs to input and use initiative-level persistence and savings adjustment data.
  - Enhanced functionality and more explicit instructions on the treatment of IESO verified savings adjustments and use of the LRAMVA threshold.

Updates to LRAM in Chapter 2 Guidelines

- Section 2.4.6.1 was updated to reinforce the policy of no retroactivity in approved balances.

- Section 2.4.6.2 was updated to enhance the reporting of LRAMVA application details.
  - Identification of key elements in LRAMVA amount sought for disposition to be provided in the application
  - Updated checklist for 2018 applications

LRAMVA Work Form (Version 2)

The LRAMVA Work Form consists of the following sheets:

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Data	**Tables 7-a to 7-j** should be populated with CDM savings persistence data provided to LDCs from the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report.

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Orientation Session
Electricity Distributors Rebasing for 2018 Rates

Accounting Matters

Review of filing requirements and models

Rajvinder Sabharwal and Donna Kwan
July 25, 2017

Agenda

1. Ontario Fair Hydro Plan
2. Accounting Standards
3. Capitalization and Depreciation Policy Changes
4. Adoption of IFRS
5. Pension & OPEBs
6. Account 1588 Power and Account 1589 Global Adjustment
7. Chapter 2 Appendices and Changes to Appendices
8. Changes to PILS model
9. DVA Lessons Learned from 2017 IRM Process
10. Clarification and Changes to DVA Continuity Schedule
11. Questions

Ontario Fair Hydro Plan (OFHP)

Documents Issued:

- OEB issued its Report on Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018 on June 22, 2017.
  - GA Modifier set at -$32.90/MWh
- OEB issued Implementation of the *Fair Hydro Act, 2017* letter on June 29, 2017
- OEB Accounting Guidance Letter to be issued shortly

OFHP – Measures effective July 1, 2017

- Bill Reductions under Part II of the OFHP Act
  - Electricity bill mitigation initiative for RPP customers through RPP prices
  - Application of GA modifier to specified customers

- Electricity-related relief programs for certain electricity consumers with respect to amendments to the OEB Act under Schedule 2 of the OFHP Act
  - Distribution Rate Protection (DRP)
  - First Nations Delivery Credit program (FNDC)

4

OFHP - Accounting

- For GA Modifier, amounts provided to the specified customers based on loss adjusted volumes are to be debited to a balance sheet account receivable/payable. LDC's are to recover the amounts recorded in this account through the settlement process with the IESO and clear out the balance sheet amount.

- DRP credits provided to the DRP customers is recorded in a balance sheet receivable/payable account. The credits provided are recovered through the settlement process with the IESO and the balance sheet account is cleared.

- FNDC credits provided to the FNDC customers is recorded in a balance sheet receivable/payable account. The credits provided are recovered through the settlement process with the IESO and the balance sheet account is cleared.

OFHP – Accounting
Bill Reductions for RPP customers

- Bill Reductions - electricity bill mitigation initiative for RPP customers through RPP prices
  - Bill reductions are achieved through the commodity price. The June 22, 2017 report describes the methodology for calculating reductions. RPP prices published in the June 22, 2017 OEB report include the embedded reductions in commodity price (GA).
  - For settlement with the IESO, distributors use the new RPP prices, and continue to account for RPP related GA as they have done in the past. Settlement process for RPP has not changed.
  - IESO has replaced Charge Type 142 with 1142. Distributors should account for Charge Type 1142, as they have done for 142 in the past.

OFHP – Accounting Global Adjustment Modifier

- Bill Reductions effective July 1, 2017 consumption - electricity bill mitigation initiative for Specified customers (customers that are RPP-eligible, but have opted out / customers that are not eligible for the RPP but are eligible for the 8% ORECA rebate)
  - Specified customers will receive bill relief in the form of a reduction to the GA charges that they would otherwise pay in the form of GA Modifier.
  - GA Modifier has been set at -$32.90/MWh for the period from July 1, 2017 to April 30, 2018.
  - For settlement with the IESO distributors make a claim for the loss-adjusted consumption of specified non-RPP customers. The claim amount will be reflected in Charge Type 1143.
  - Distributors would be billing the specified customers the GA rate net of the GA Modifier

OFHP – Accounting
Amendments to the OEB Act under Schedule 2 of the OFHP Act

- Distribution Rate Protection (DRP) applicable to eligible customers served by the 8 licensed distributors (DRP distributors)
  - See June 29, 2017 OEB letter for a description of DRP distributors and DRP eligible customers
  - DRP program provides for a cap on the amount that DRP-eligible customers can be charged for base distribution charges, which consist of the base monthly fixed service charge and base variable distribution charge. In the D&O dated June 22, 2017 OEB set the cap at $36.43.
  - DRP distributors must calculate the actual total base distribution charge and compare this to the maximum OEB approved charge no more than the maximum amount.
  - DRP distributors claim the difference from the IESO.
  - The amount claimed will appear as the new CT 706 on the IESO invoice.

Accounting Standards

- Utilities must have converted to International Financial Reporting Standards (IFRS) by January 1, 2015.

- Accounting Standards used in rate applications include:
  - IFRS as set out in Part I of the CPA Canada Handbook
  - The OEB may permit utilities to use US GAAP and Accounting Standards for Private Enterprises. Utilities must request prior approval from the OEB.

- Filing Requirements and Chapter 2 Appendices are structured for applicants that adopted IFRS January 1, 2015.

Key References

Key References for interpreting Filing Requirements

- Report of the Board: Transition to IFRS (EB-2008-0408), July 28, 2009
- 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 OEB Letter – Changes to depreciation expense and capitalization policies
- June 25, 2013 OEB Letter – Accounting policy changes for Accounts 1575 and 1576
- March 31, 2015 APH Guidance Item #s 6 -8
- July 25, 2016 Accounting Guidance on Capacity Based Recovery
- Report of the Ontario Energy Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040), May 18, 2017

Capitalization and Depreciation Policy Changes

- Per the OEB letter dated July 17, 2012, distributors remaining on CGAAP were permitted to make regulatory accounting changes for capitalization and depreciation expense policies effective January 1, 2012. These changes were mandatory by January 1, 2013.

- Many 2018 applicants last rebased with updated capitalization and depreciation policies.

- If capitalization and depreciation policies changed since the last rebasing application, identify the changes and the cause of the changes.

Adoption of IFRS

- Must identify all material changes in the adoption of MIFRS that impacts the application.
  - Impacts should be quantified and explanation and details of the changes should be provided.

- Must complete Appendix 2-Y regarding summary of impacts to the components of revenue requirement from transition to MIFRS (e.g. rate base, operating costs)
  - For applicants reflecting capitalization and depreciation policy changes in the current application, the comparison is between MIFRS and CGAAP prior to policy changes .
  - For applicants that reflected capitalization and depreciation policy changes in a prior application, the comparison is between MIFRS and CGAAP after policy changes.

Pension & OPEBs

Report of the Ontario Energy Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040) issued May 18, 2017 for comment on implementation matters.

- Establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates in the circumstances of any given utility.
- Provides for establishment of a variance account to track the difference between forecasted accrual amount in rates and actual cash payment(s) made, with an asymmetric carrying charge in favour of ratepayers applied to the differential.

Pension & OPEB (cont)

Application to include filings on:

- proposed recovery method (i.e. accrual or cash)
- breakdown of the pension and OPEBs amounts included in OM&A and capital
- most recent actuarial report
- evidence to support the quantum
- rationale and evidence if adopting cash method
- quantify impact of transition, if proposing to transition

Accounts 1588 Power and Account 1589 Global Adjustment

GA Analysis Workform

- To be completed in tabs 7 and 7.a of the DVA Continuity Schedule
- The workform calculates an approximate expected balance in Account 1589 RSVA - GA and compares it to the balance in the general ledger. Material differences between the two need to be reconciled and explained.
- Refer to power point presentation and example from July 19, 2017 posted on OEB’s website for further details

Certification of Evidence

- Certification by the Chief Executive Officer, or Chief Financial Officer or equivalent
- Certify that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed

Chapter 2 Appendices

Three scenarios are generally expected:

		Reflecting Accounting Policy Changes in Current Application		Reflected Accounting Policy Changes in Prior Application[3]
		1) Accounting Policy Changes in 2012 and Adopted IFRS in 2015	2) Accounting Policy Changes in 2013 and Adopted IFRS in 2015	3) Adopted IFRS in 2015
Information to be filed in 2018 CoS Application	2018Test	MIFRS	MIFRS	MIFRS
	2017Bridge	MIFRS	MIFRS	MIFRS
	2016Historical	MIFRS	MIFRS	MIFRS
	2015Historical	MIFRS	MIFRS	MIFRS
	2014Historical	MIFRS and Revised CGAAP	MIFRS and Revised CGAAP	MIFRS and Revised CGAAP
	2013Historical	Revised CGAAP	CGAAP and Revised CGAAP[2]	N/A
	2012Historical	CGAAP and Revised CGAAP	N/A	N/A

- Scenario 1 + 2 - For the year that the applicant implemented changes to its capitalization and depreciation policies (2012 or 2013), the applicant must file two sets of appendices, one before and one after the policy changes
- Scenario 1-3 - For the transition year (typically 2014), the applicant may file two sets of appendices, one under Revised CGAAP and one under MIFRS. Revised CGAAP schedules are optional depending on the materiality of impacts.

Changes to Chapter 2 Appendices

2-C Depreciation schedules revised – one generic appendix for all 3 scenarios

Scenario that applies	Applicable Years and Accounting Standard	Year Reflected in Schedule Below	Accounting Standard Reflected in Schedule Below
Rebasing for the first time with depreciation policy changes made in 2012. ☐	This appendix must be duplicated and completed for the years 2012 to 2018. The appendix for 2012 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2012 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2015 to 2018 is to be completed under MIFRS.		
Rebasing for the first time with depreciation policy changes made in 2013. ☐	This appendix must be duplicated and completed for the years 2013 to 2018. The appendix for 2013 is to be completed under CGAAP (prior to changes in depreciation policies). The appendix for 2013 to 2014 must be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2015 to 2018 is to be completed under MIFRS.		
Already rebased with depreciation policy changes in a prior rate application ☐	This appendix must be completed for 2014 to 2018. The appendix for 2014 is to be completed under Revised CGAAP (after changes in depreciation policies). The appendix for 2015 to 2018 is to be completed under MIFRS.		

Changes to PILS Model

- Elimination of the eligible capital property rules and introduction of a new class of depreciable property, class 14.1, effective January 1, 2017.
- Integrity checklist moved into PILS model

DVA Lessons Learned from 2017 IRM Process

- IESO RPP/GA settlement true-ups
  - True-ups for Accounts 1588 and 1589 were not being done frequently enough (e.g. more than a year).
  - True-ups were not reflected in the year to which they relate.
    - OEB letter dated May 23, 2017, titled *Guidance on Disposition of Accounts 1588 and 1589*, addressed this.

- Embedded generation reporting to IESO impacting GA settlement
  - Some utilities incorrectly reported embedded generation volumes to the IESO. This causes IESO to bill LDCs GA incorrectly, which can lead to significant discrepancies to Account 1589 that impacts balances of Accounts 1588 and 1589 being disposed.

- GA unbilled revenue discrepancies
  - Some LDCs accrued different amounts for Class A for unbilled revenue as compared cost of power. Accruals should be on the same basis (i.e. on peak demand factor).
  - Some LDC's accrued incorrect GA rate for unbilled revenues. For example, if non-RPP Class B Customers are billed on 1st estimate GA , then unbilled revenue must be accrued on 1st estimate GA.
  - This created a variances in Account 1589, which would be incorrectly disposed to Class B customers

DVA Lessons Learned from 2017 IRM Process (cont)

- GA pricing by customer class:
  - Some LDC's did not use consistent GA prices for billing non-RPP customers within each customer class. For example, all non-RPP Class B customers in the General Service > 50 kW class must be billed the same GA rate (i.e. 1st or 2nd estimate or the actual GA rate)
  - If a utility wants to make a change to the rate used to bill a class, this must be done at the beginning of a year

- Account 1588
  - Distributors settle with the IESO for the differences between amounts billed for energy and amounts paid to the IESO, theoretically, there should be a very small balance in account 1588 to reflect unaccounted for energy (i.e. the differences between loss factors billed to customers compared to actual system losses).
  - For some distributors Account 1588 had a large balance over the longer term. If this is the case, a distributor must be able to justify why.

- Account 1589
  - A number of distributors had significant balances in Account 1589 that could not be explained. The OEB requested further analysis of the account and going forward the OEB will require the completion of the GA Analysis Workform.

DVA Lessons Learned from 2017 IRM Process (cont)

- Account 1595 not accounted for and disposed correctly
  - Not all distributors were accounting for recoveries of regulatory assets/liabilities in Account 1595 consistent with the October 2009 and July 2012 FAQ.
  - Some distributors sought disposition of Account 1595 sub-account on a final basis before the end of the disposition period.
  - Some distributors sought disposition of one Account 1595 sub-account in multiple applications (i.e. sub-account was not disposed once on a final basis)
    - Filing requirements have been updated to address this.

- DVA Continuity for Account 1580 CBR sub-accounts
  - A number of distributors didn't record amounts to the new CBR Class A and Class B sub-accounts. Where an LDC does not have any Class A customers, transactions must still be recorded to the Class B CBR Sub-Account.

Clarification Points to DVA Continuity Schedule

See footnotes of DVA Continuity Schedule for further instructions

- Each account and sub-account that the utility has approved for use as at Dec. 31, 2016 must be listed, regardless of whether disposition is being requested for the account

- RPP Settlement true up claims pertaining to the period that is being requested for disposition must be reflected in Accounts 1588 and 1589. This would include any true up in the pro-ration of the GA charge and differences between accrued GA and actual GA billed by the IESO for non-RPP customers as well.
  - If the RPP Settlement true-up claim was not reflected in the account balance at the end of the last year that was previously disposed, then no adjustment would have to be made to the opening balance of the first year being requested for disposition.

- Account 1589
  - Any balances pertaining to Class A customers should not be included in the account balance requested for disposition

Clarification Points to DVA Continuity Schedule (cont)

- Class A/B transition customers
  - Transition customers that are allocated a customer specific GA and/or CBR B balance are not to be charged the general GA and/or CBR B rate riders
  - Customers should be charged in a consistent manner for the entire rate rider period until the sunset date.
    - E.g. If a customer was a non-RPP Class B customer being charged the Global adjustment rate rider, they should continue to be charged the rate rider if they switched to Class A during the rate rider recovery period

- No disposition of Account 1580, sub-account CBR Class A. If a balance exists for the sub-account as at Dec. 31, 2016, the balance must be explained.

- Account 1595
  - The audited balance in the account is only to be disposed a year after the recovery/refund period has been completed.

- Account 1508
  - Any utility specific 1508 sub-accounts requested for disposition must have supporting evidence showing how the annual balance is derived. The relevant accounting order must be provided.

Changes to DVA Continuity Schedule

- Tab 1.1 Instruction Sheet (new tab)

- Tab 2 Continuity Schedule
  - Flexibility to add utility specific 1508 sub-accounts
  - Checkbox to indicate if you had any Class A customers during the period that the Account 1589 GA balance accumulated
  - Checkbox to indicate if you had any Class A customers during the period where the balance in 1580 sub-account CBR Class B accumulated

- Tab 5.1 Class A Consumption Data (new tab if Class A customers existed as indicated in Tab 2)
  - Input consumption data on transition customers and customers that were Class A for entire period that the GA balance accumulated

- Tab 5.2 GA Allocation (revised tab if transition customers existed as indicated in Tab 5.1)
  - Calculates customer specific allocation of GA balance to transition customers (Class B to Class A and vice versa), if applicable.

Changes to DVA Continuity Schedule (con't)

- Tab 5.3 CBR B (new tab if Class A customers existed as indicated in Tab 2)
  - Calculates billing determinant for separate CBR B rate rider, if applicable

- Tab 5.3a CBR B Allocation (new tab if transition customers existed as indicated in Tab 5.1)
  - Calculates customer specific allocation of CBR B balance to transition customers (Class B to Class A and vice versa), if applicable.

- Tab 6 Rate Rider Calculations
  - A separate rate rider is only calculated for Accounts 1580 and 1588 for rate classes that have WMP customers. Otherwise, Accounts 1580 and 1588 are included in the general Group 1 DVA rate rider.
  - New CBR B rate rider table, if applicable

- Tabs 7 and 7.1 GA Analysis Workform (new tabs)

Questions?