ONTARIO ENERGY BOARD

Very Small Distributors (VSD) Cost of Service Model Training

For 2027 and 2028 Filers

Disclaimer: this training uses Cost of Service Models designed for 2026 rate applications

September 3 & 4, 2025

Housekeeping Items

- Please mute yourself when entering the meeting.
  - Participants will be able to unmute themselves if they wish to speak.
- To ask questions or provide comments, please use the chat feature.
  - Address questions to All Participants.
- When the moderator calls your name, ask your question via audio by unmuting yourself.
- Please state your name and organization when speaking.
- Turning on your video is optional.
- This session will be recorded and made available later.
- If you are having problems, please contact OEB IT: ITHelp@oeb.ca

Agenda – Day 1

01	Welcome and Land Acknowledgement
02	Chapter 2 Appendices
03	RRWF (Revenue Requirement Workform)
	BREAK
05	Tariff Schedule and Bill Impact Model
06	PILs Workform
07	DVA Continuity Schedule + Instructions
08	Q&A

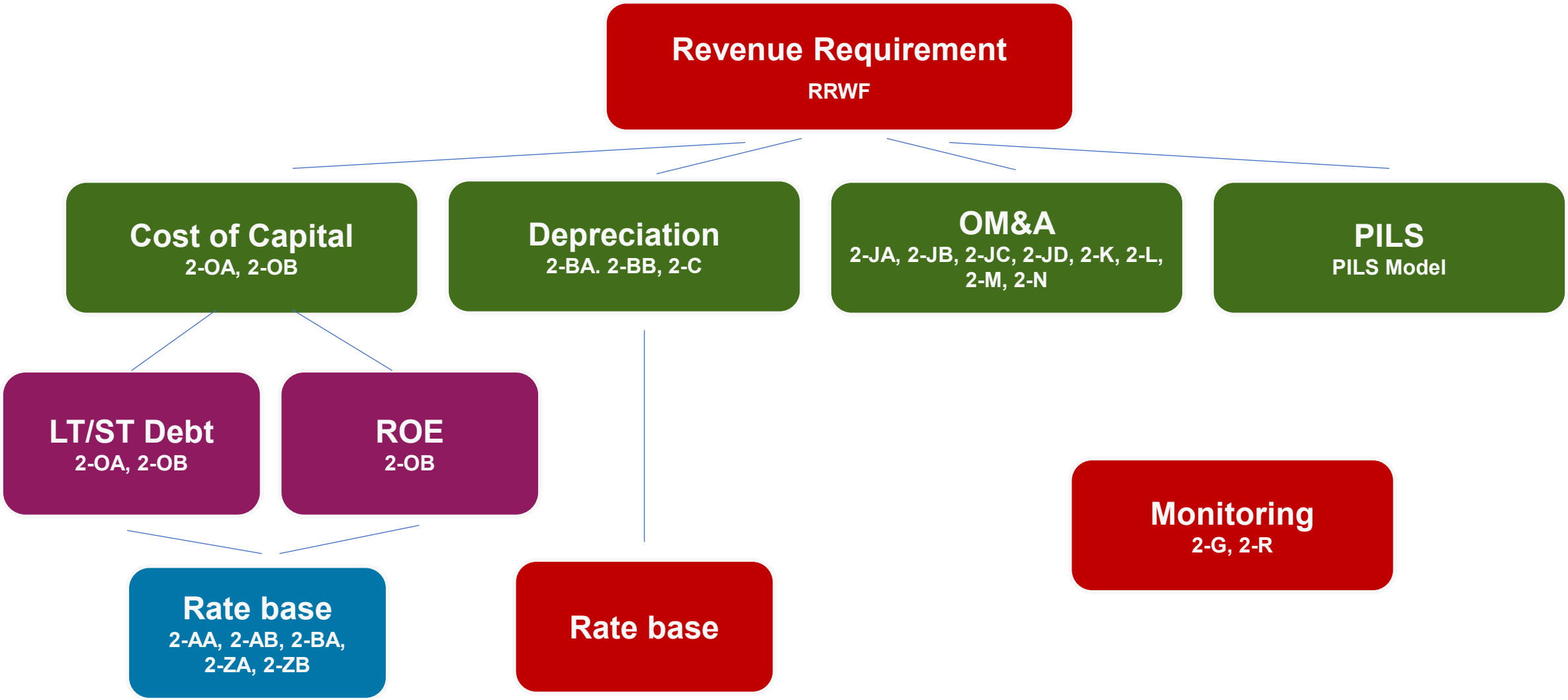
Land Acknowledgement

The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples. This area is now home to many diverse First Nations, Inuit and Métis peoples. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit.

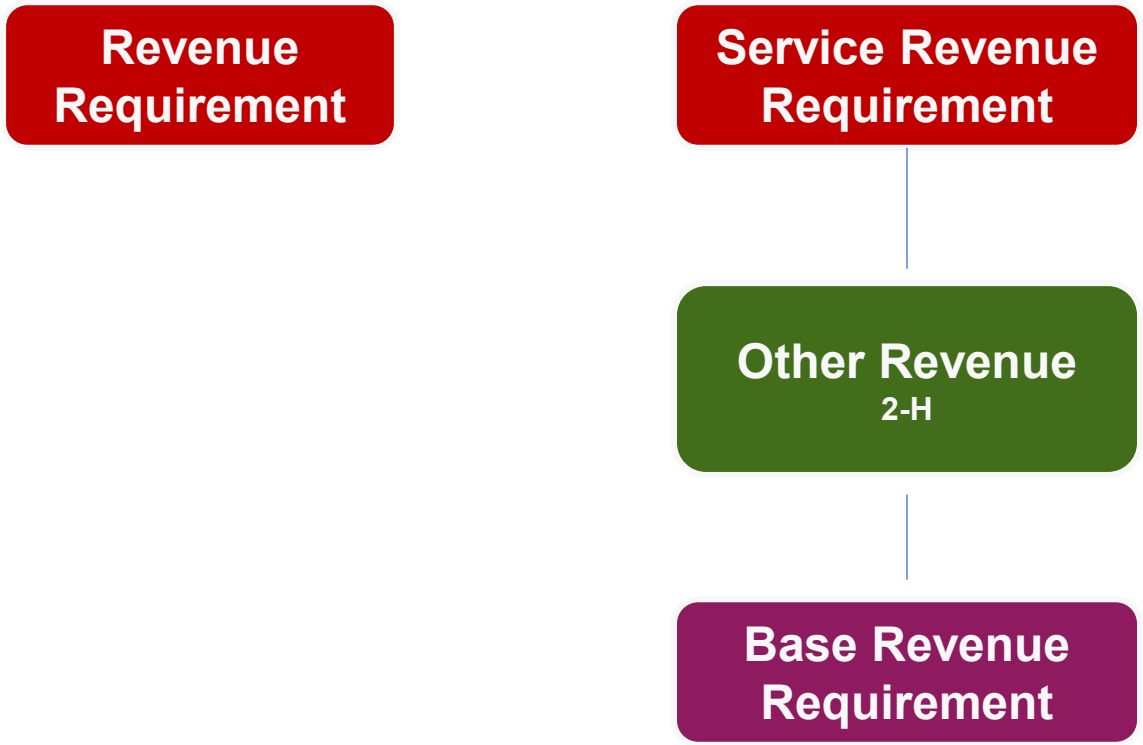
As we gather, we acknowledge that we are coming together from diverse regions, each with its own Indigenous peoples, ancestral lands, and treaties. We recognize and honour the Indigenous communities, their elders, past and present, as the traditional custodians of these lands.

We are grateful for the opportunity to gather and work on these lands and recognize our shared responsibility to support and be good stewards of them.

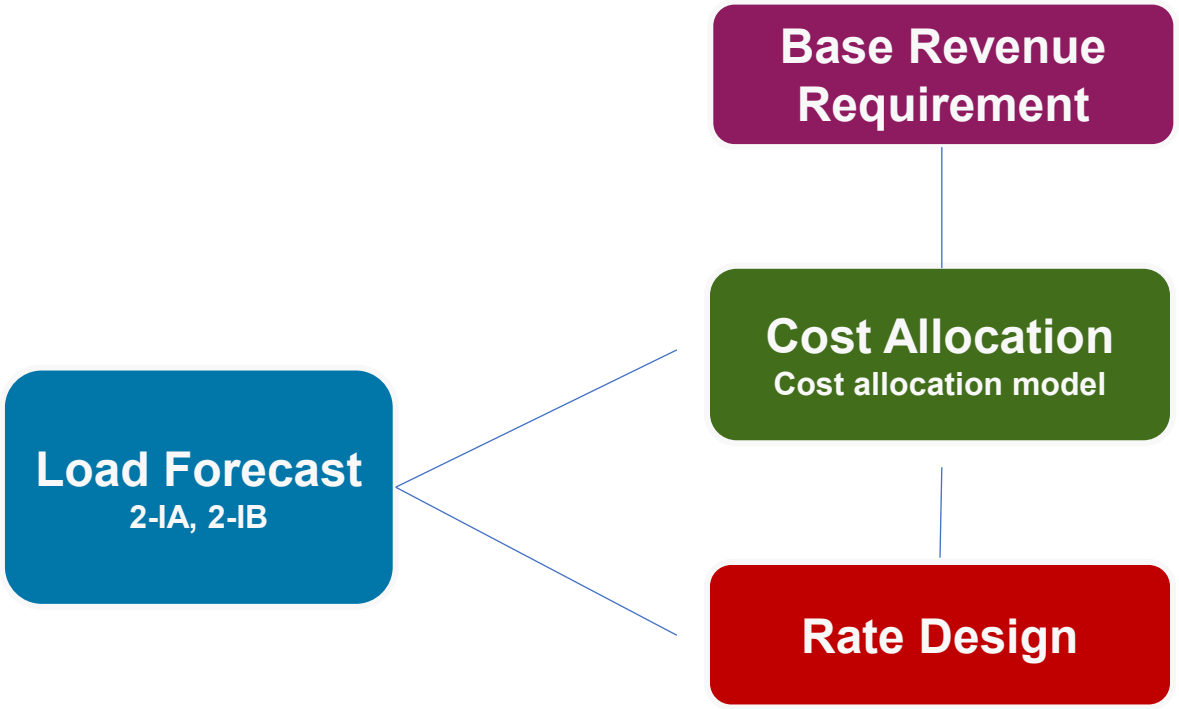
Model Overview



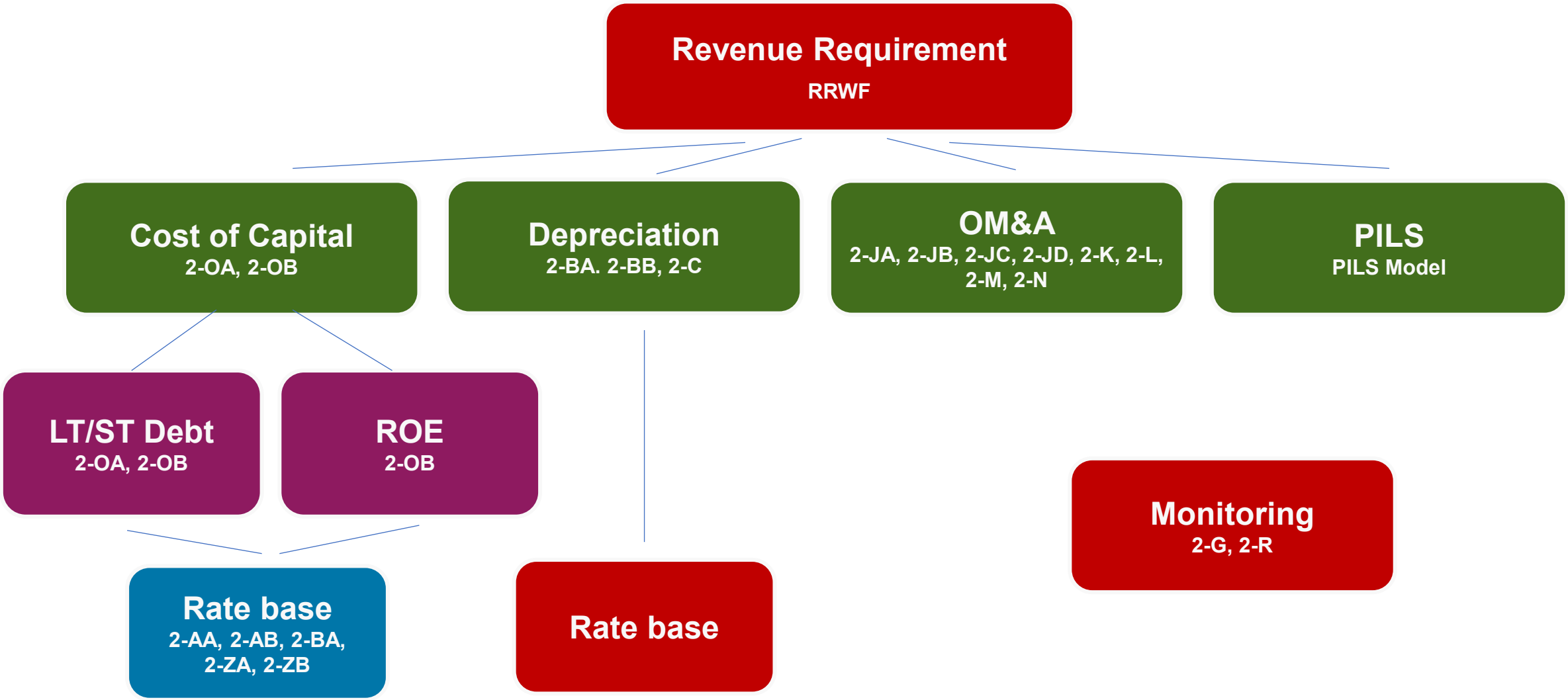
Model Overview



Model Overview



Model Overview



Capital and Rate Base

Rate base

Key Components:

- Distribution System Plan
- In-Service Addition/Disposals
- Working Capital Allowance

Exhibits:

- Exhibit 2
- Chapter 2 Appendices – 2-AA, 2-AB, 2-BA, 2-ZA, 2-ZB

Capital, Rate Base, and Depreciation

Things to check:

- System Access, System Renewal, System Service, General Plant, Capital Contribution and Total should reconcile.
- Capital expenditures should match in-service additions if that is how the utility does it.
- Large variances between planned and actual should be explained
- Large projects in historical/forecast rate years should be explained
- Average rate base and depreciation should match the RRWF

OM&A

Things to check:

- 2-JA, 2-JB, and 2-JC/2-JD totals should reconcile
- Number of customers in 2-L should reconcile with load forecast

Revenue Requirement Workform

Things to check:

- Data Input Sheet
  - Rate base – 2-BA, 2-JA, 2-ZB
  - Other Revenue – 2-H
  - OM&A – 2-JA
  - Depreciation – 2-BA
  - PILs – PILs Workform
  - Cost of capital – 2-OA, 2-OB
  - Load forecast – load forecast model
  - Cost allocation – cost allocation model

Revenue Requirement

Depreciation

Key Components:

- Gross Fixed Assets
- Accumulated Depreciation
- Useful life - Kinectrics Report

Exhibits:

- Exhibit 2
- Chapter 2 Appendices (2-BA, 2-BB, 2-C, 2-D)
- RRWF
- Income Tax/PILS Workform

Revenue Requirement

PILS

Key Components:

- Taxable income
- PILs Smoothing Adjustment
- Property tax

Exhibits:

- Exhibit 6
- RRWF
- Income Tax/PILS Workform
- Worksheet – Account 1592, Sub-account CCA Changes

Account 1592 Sub-account CCA Changes & Smoothing Mechanism

Observation 3: Some distributors either did not provide the smoothing calculation as part of the pre-filed evidence in the cost-based applications or did not calculate the smoothing mechanism correctly.

OEB Policy

The Accelerated Incentive Investment Program (AIIP) is still in effect until 2027. As a result, the CCA change sub-account under Account 1592 needs to be used for the cost-based applications for the rate years until 2027.
Chapter 2 of Filing Requirements states that:

"Distributors may propose a mechanism to smooth the tax impacts over the five-year IRM term. The OEB will assess a distributor's smoothing proposal on a case-by-case basis. If the OEB approves the smoothing proposal, the distributor's use of (or access to) Account 1592 will no longer be applicable."

Requirements

- ✓ The distributor should provide the calculation of the smoothing mechanism as part of the pre-filed evidence. In addition, the calculation should be done correctly.
- ✓ Smooth the tax impacts over the five-year IRM term.
- ✓ If PILs is not smoothed over the IRM term, Account 1592 would generally be expected to be used since the AIIP will be phased out starting in 2024.

Rebasing period for 2025~2029 and applying AIIP

Smoothing Adjustment			
	2028	2029	Cumulative Total
	Forecast	Forecast	Forecast
CCA Legacy (Half-year)	2,303,514	2,947,163	5,250,677
CCA Bill C-97	2,069,478	2,573,934	4,643,412
CCA Difference	234,036	373,229	607,265
Take 1/5 of Difference			121,453

Correction	
Net Income Before Taxes	1,385,710
Other Addition: Smoothing Mechanism	121,453
Total Additions	2,363,319
Deductions	3,268,532
Net Income	601,950
Tax	26.50%
Income Tax	159,517
Gross up PILS	217,030
Test Year PILS	217,030

Deferral and Variance Accounts

DVA Continuity Schedule

Key Components:

- Group 1 & Group 2
- Principal adjustment
- Consumption data
- Rate Rider Calculations

Exhibits:

- Exhibit 9
- DVA Continuity Schedule

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Agenda – Day 2

01	Commodity Accounts Analysis WF + Instructions
02	Load Forecasting methodology Cost Allocation Model
	BREAK
03	Revenue to Cost Ratio Adjustment Model
04	RTSR Workform
05	LRAMVA Workform + Instructions and BCA excel template
06	ICM/ACM Model
07	Q&A

Deferral and Variance Accounts

Commodity Accounts Analysis Workform

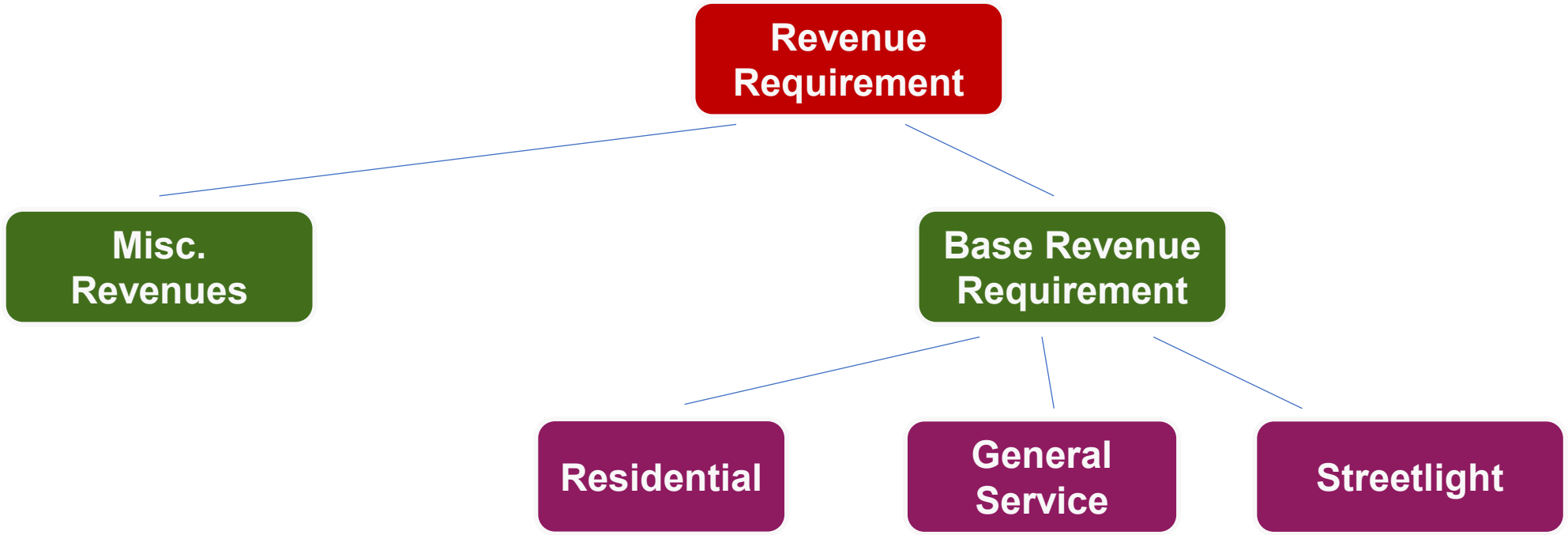
Key Components:

- Accounts 1588 / 1589
- Principal adjustment

Exhibits:

- Exhibit 9
- Commodity Accounts Analysis Workform

Recovery of Revenue Requirement



Revenue = Fixed Charge * Customer Count * 12 + Volumetric Rate * Volume (kWh / kW)

Rate Setting Forecasts Required

Customer / Connection Forecast

- ✓ Historical Growth Trending
- ✓ Underpins the Fixed Monthly Charge for all rate classes

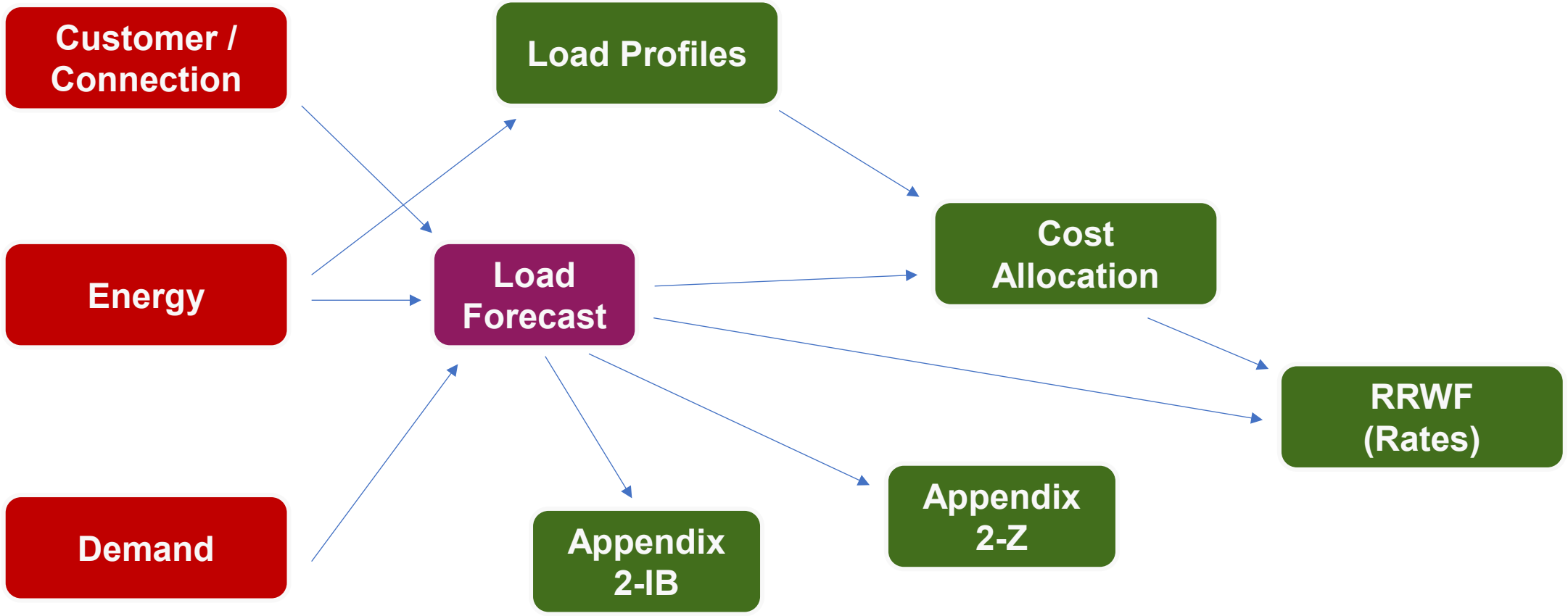
Energy Forecast (kWh)

- ✓ Normalized Average Consumption
- ✓ Regression Methodologies
- ✓ Underpins cost of power, and volumetric rates for rate classes that are energy billed

Demand Forecast (kW)

- ✓ Typically based on Energy Forecast
- ✓ Underpins volumetric rates for rate classes that are demand billed

Load Forecast in Rate Making



Customer / Connection Forecast

Customers for metered rate classes, connections for unmetered rate classes

Common Methodologies	Common Problems		Common Resolution
✓ Average Growth	Change in Trends	→	Change time horizon
✓ Geometric Mean Growth	New developments		
	• News	→	Manual Adjustments as required.
	• Residential Subdivisions	→	Add exceptional customer growth less any normal subdivision growth
	Reclassification	→	Forecast trends assuming customers have always been in their new classes

Energy Forecast

Kilowatt-hours (kWh)

Common Methodologies

- ✓ Regression
  - ✓ Linear
  - ✓ Log Log
  - ✓ Other
- ✓ Normalized Average Consumption

Common Implementations

Class-by-class Regression models

Wholesale Purchase Regression

- Forecasting rate classes with ratio of rate class to wholesale
- Forecasting rate classes with NAC, and allocation of difference to weather sensitive classes

Seldom used, but available

Normalized Average Consumption

Normally used for unmetered classes, Simple low-cost option for all classes

Common Methodology

1. For each rate class, and each historic year, calculate consumption per customer.
2. Calculate average across the years
3. Multiply by forecasted customers

Common Problems

Trend in consumption per customer

Major shift in consumption

Recession / Anomalous years

Common Resolution

Use a historic trend rather than historic average

Consider using a more recent average

Consider dropping impacted years from average.

NAC is not well suited to addressing multiple explanatory factors

Adjustments

Used where impacts can be isolated and identified better than regression

Common Scenario	Approach
1. Conservation and Demand Management	Savings can be independently measured
2. Electrification	Exponential growth expected, and no variables are on an exponential trend
3. Re-classifications and large customers	History of affected customers is known
4. Supply not included in Wholesale Purchases	Embedded generation or wholesale market participants load

Demand Forecast

Only for Demand Billed rate classes

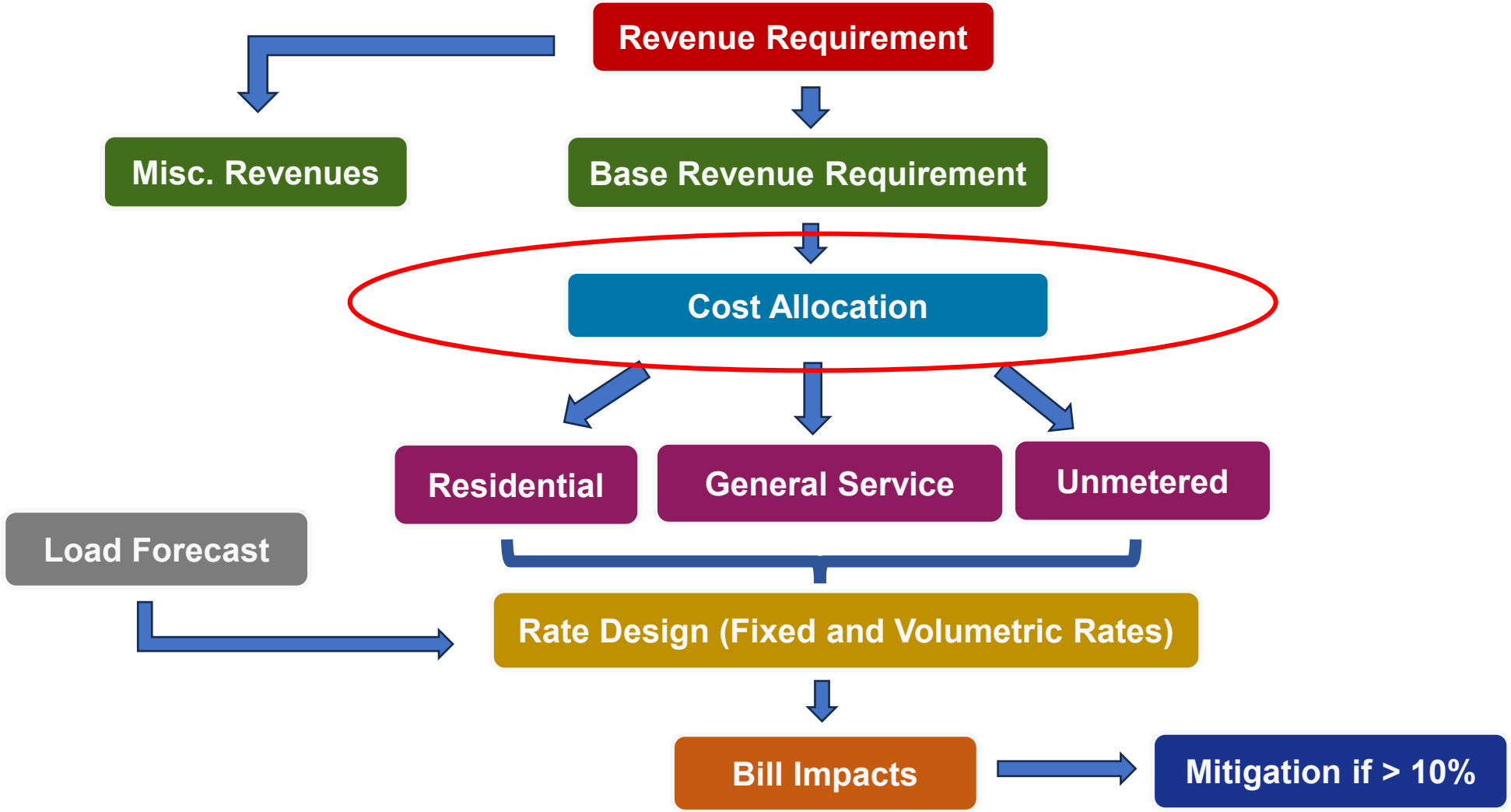
Common Methodologies	Common Problems		Common Resolution
✓ Historic Average kW/kWh ratio	Customer Mix Change	→	Change time horizon
	• New Customer		Use estimated demand factor until known
	CDM / Peak Shaving	→	Change time horizon
			Consider trending
	Reclassification	→	Consider utility proposal, perhaps weighted average of multiple rate classes

Adjustments

Used where impacts can be isolated and identified better than regression

Common Scenario	Approach
1. Conservation and Demand Management	Savings can be independently measured
2. Electrification	Exponential growth expected, and no variables are on an exponential trend
3. Re-classifications and large customers	History of affected customers is known or estimated better than approaches

Steps in Setting Rates



What is Cost Allocation?

Cost allocation is the process of identifying, accumulating and assigning costs to specific cost objects.

For utilities, cost allocation is one part of the utility regulatory process which determines which customers are responsible for certain costs associated with operating the electricity system.

The objective of cost allocation is to ensure that costs are allocated fairly and equitably. Costs are attributed to customers based on how utility costs are incurred or who benefits from the investment.

Cost allocation typically occurs after a cost-of-service study, which determines the utility's revenue requirement, and before a rate design study, which determines what and how customers will be charged.

Together cost allocation and rate design ensure that customers are charged fairly, and utilities receive enough revenue to reliably operate the system.

The OEB's Cost Allocation Model (CAM)

The CAM is designed to allocate the costs to provide service to the various customer rate classes based on cost causality principles:

Costs should be allocated to those customer classes causing them.

Sheet I3 Trial Balance

Data Sources:

Top table: ROE, Taxes, Interest Expense, Revenue Requirement, Rate Base
Revenue Requirement Work From
Main Table (Trial Balance): Accounting System

Watch out:

Model based on CGAAP accounts, not updated for IFRS
Account 4235 needs to be split to separate Account Set Up Charges

Validation:

Model checks for consistency of Revenue Requirement and Rate Base

Sheet I4 Breakout Assets

Data Sources:

Chapter 2, Appendix 2-BA (US of A balances)
System knowledge (Primary vs Secondary proportions)

Watch out:

Model based on CGAAP accounts, not updated for IFRS
Appendix 2-BA is based on year opening / closing costs, cost allocation is year average

Validation:

Model checks for consistency with trial balance on the prior tab

Sheet I5.2 Weighting Factors

Services:

Relative cost of the distributor owned assets dedicated to the connection of the average customer in each class

This is frequently zero where customers are required to provide their own connection assets.

Billing and Collecting:

Relative cost to bill and collect from a customer in each rate class

This is per customer bill, not per connection

It includes all costs in accounts 53xx except Meter Reading, and Bad Debt

Sheet I6.1 Revenue, I6.2 Customer Data

Data Sources:

Load Forecast – as seen on the RRWF
Current Tariff of rates and charges
Billing system for proportion of load receiving Transformer Ownership Allowance

Watch out:

Number of Devices and Connections need to be completed for Street Light, Sentinel and USL classes.
Customers refers to customer accounts
Connections refers to connections to the distribution system
Devices refers to the typical billing unit, a single lamp for streetlights.

Validation:

Revenues balanced against forecasted revenue in RRWF

Sheet I7.1 Meter Capital, I7.2 Meter Reading

Data Sources:

Installed meter costs – Utility records

Validation:

Number of meters should be appropriate for the number of customers

- Same or slightly more meters

Number of meter reads should be appropriate for the number of meters

Meter types and read types should be reasonable for the rate class.

Sheet I8 Demand Data

Data Sources:

Load Profiles

Watch out:

This underpins the single most important allocator

Validation:

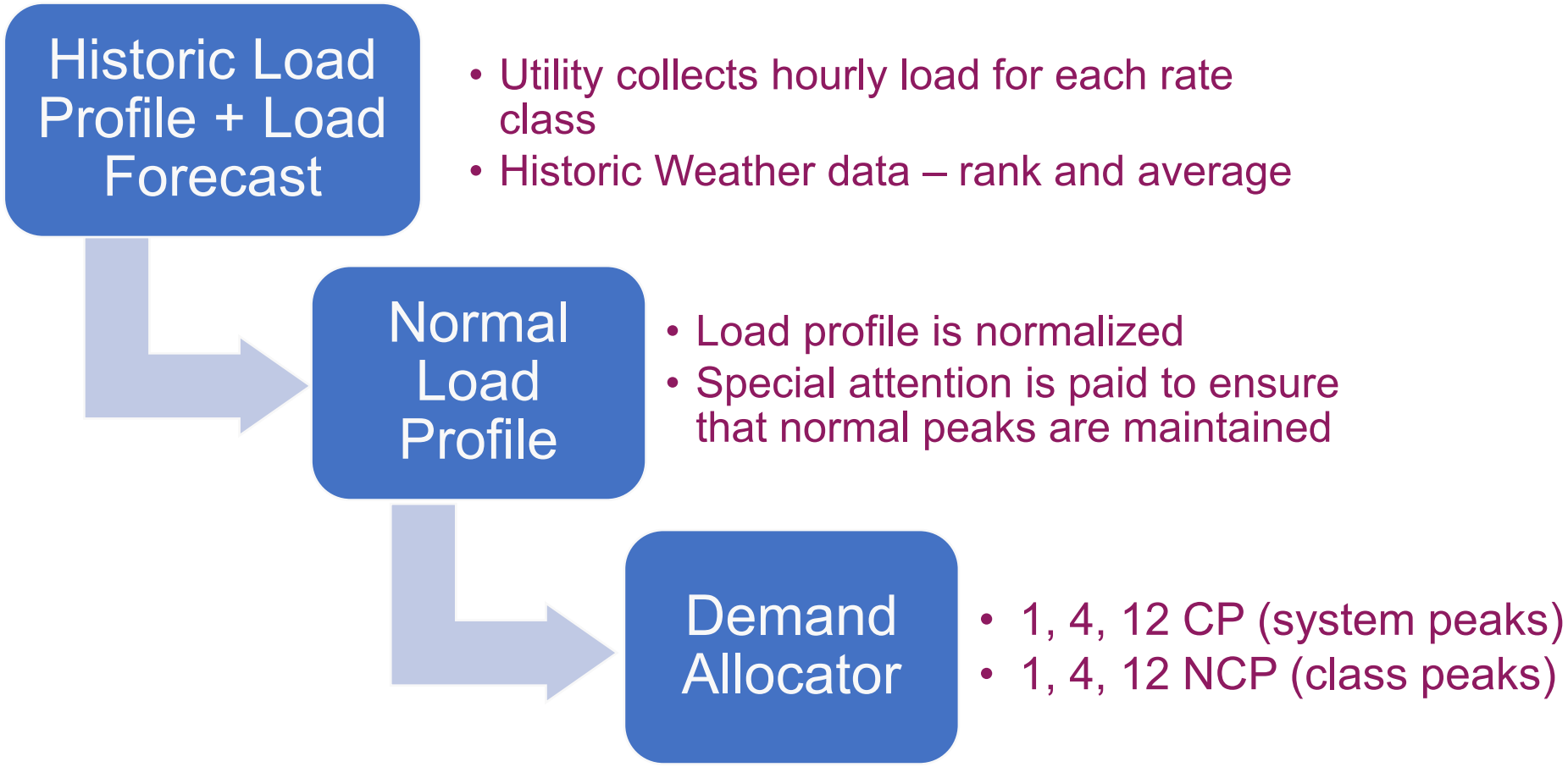
Model provided validation should be passed

Customer counts on I6.2 should be consistent with Load on I8.

Line Transformer reflects customers using LDC line transformers

Transformer Ownership Allowance on I6.1 is paid to customers supplying their own transformer.

Allocation – Load Profiles



Revenue to Cost Ratio – Tab O1

The result of applying a cost allocation methodology is the determination of a ratio of the revenues to the allocated costs. The ratio is conventionally expressed as a percentage – the percentage of costs that are recovered through revenue.

The percentage identifies the rate classes that paying more (over 100%) or less (under 100%) than allocated cost of serving those rate classes.

But… Cost Allocation is as much an art as a science. It is full of estimates and proxies. Therefore, the allocated costs are an estimate, and where the revenue-to-cost ratio is close to 100%, we can't be sure whether the rate class is paying more or less than the costs it imposes.

Revenue to Cost Ratio – Ranges

Revenue Requirement Workform, Tab 11. Cost Allocation:

Revenue Requirement reflect adjusted revenue to cost ratios for GS < 50 kW, GS 50 to 4,999 kW and Sentinel Lighting rate classes.

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2014	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	101.70%	103.45%	103.45%	85 - 115
General Service < 50 kW	116.00%	118.31%	116.60%	80 - 120
General Service 50 to 4,999 kW	84.90%	79.14%	80.00%	80 - 120
Sentinel Lighting	80.00%	67.01%	71.34%	80 - 120
Street Lighting	86.60%	89.96%	89.96%	80 - 120
Unmetered Scattered Load	116.80%	101.54%	101.54%	80 - 120

Total revenue requirement remain unchanged – only $ revenue requirement amounts shift between rate classes.

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 4,108,236	$ 4,526,450	$ 4,526,450	$ 277,607
2	General Service < 50 kW	$ 914,511	$ 1,007,608	$ 992,398	$ 46,065
3	General Service 50 to 4,999 kW	$ 991,308	$ 1,092,222	$ 1,104,850	$ 66,541
4	Sentinel Lighting	$ 10,821	$ 11,922	$ 12,783	$ 1,401
5	Street Lighting	$ 81,476	$ 89,771	$ 89,771	$ 12,143
6	Unmetered Scattered Load	$ 11,645	$ 12,830	$ 12,830	$ 1,301
	Total	$ 6,117,997	$ 6,740,803	$ 6,739,081	$ 405,057

Fixed/Variable Split

Base Revenue Requirement (Distribution Revenue)

= Fixed Revenue Requirement + Volumetric Revenue Requirement

(Fixed Charge x Customer Count x 12) (Volumetric Charge x Volume (kWh/kW))

= (% Fixed + % Volumetric) x Base Revenue Requirement

Fixed/Variable Split

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Fixed/Variable Split

Revenue Requirement Workform, Tab 13. Rate Design

Stage in Process:		*Settlement Agreement*									
		Customer and Load Forecast				Class Allocated Revenues			Fixed / Variable Splits [2,3]	
						From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Percentage to be entered as a fraction between 0 and 1	
	Customer Class From sheet 10. Load Forecast	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable
1	Residential	kWh	11,741	95,562,231	-	$ 4,526,450	$ 4,526,450	$ -	100.00%	0.00%
2	General Service < 50 kW	kWh	1,168	35,768,954	-	$ 992,398	$ 513,899	$ 478,499	51.78%	48.22%
3	General Service 50 to 4,999 kW	kW	126	135,154,245	317,655	$ 1,104,850	$ 284,301	$ 820,548	25.73%	74.27%
4	Sentinel Lighting	kW	157	99,191	276	$ 12,783	$ 8,129	$ 4,654	63.59%	36.41%
5	Street Lighting	kW	2,974	867,519	2,416	$ 89,771	$ 65,272	$ 24,498	72.71%	27.29%
6	Unmetered Scattered Load	kWh	96	366,146	-	$ 12,830	$ 8,917	$ 3,913	69.50%	30.50%

Example: General Service < 50 kW

% Fixed Portion = $513,899 / $922,398 = 51.78%

% Volumetric Portion = 100% - 51.78% = 48.22%

Fixed Revenue = $51.78% x $992,398 = $513,899

Volumetric Revenue = $992,398 - $513,899 = $478,499

Fixed/Variable Split – (Cont'd)

Fixed Charge - Floor

Fixed Charge - Ceiling

Cost Allocation Model, Tab O2	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$7.31	$8.92	$91.81	$0.86	$1.71	$1.69
Customer Unit Cost per month - Directly Related	$11.98	$14.06	$143.69	$1.46	$2.92	$3.12
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$21.74	$22.76	$184.54	$2.86	$10.36	$8.26
Existing Approved Fixed Charge	$29.16	$36.65	$187.83	$1.66	$3.65	$7.00

Rate Class	Current Fixed/Variable Split		Proposed Base Revenue Requirement			Customer Number/ Connections	Volume (kWh or kW)	Volumetric Charge Determinant	Fixed Charge ($/Month)	Volumetric Charge ($/kWh or $/kW)
	Fixed Revenue Portion	Variable Revenue Portion	Total	Fixed	Volumetric					
Residential	100%	0.00%	$ 4,526,450	$ 4,526,450	$ -	11,741	95,562,231	kWh	$ 32.13	$ -
GS < 50 kW	56.19%	43.81%	$ 992,398	$ 557,666	$ 434,731	1,168	35,768,954	kWh	$ 39.77	$ 0.0122
GS > 50 kW	26.19%	73.81%	$ 1,104,850	$ 289,397	$ 815,453	126	317,655	kW	$ 191.20	$ 2.5671
Sentinel Lighting	63.59%	36.41%	$ 12,783	$ 8,129	$ 4,654	157	276	kW	$ 4.31	$ 16.8798
Street Lighting	72.71%	27.29%	$ 89,771	$ 65,276	$ 24,495	2,974	2,416	kW	$ 1.83	$ 10.1395
Unmetered Scattered Load	69.50%	30.50%	$ 12,830	$ 8,917	$ 3,913	96	366,146	kWh	$ 7.71	$ 0.0107
Total			$ 6,739,081	$ 5,455,835	$ 1,283,246	16,263	132,017,678			

Proposed base revenue requirement from RRWF, Tab 11. Cost Allocation

Example: General Service < 50 kW

Fixed Revenue = (Total Revenue x % Fixed Portion) = $992,398 x 56.19% = $557,666

Fixed Charge = Fixed Revenue /12 Months / # of Customers = $557,666 / 12 / 1,168 = $39.77 / Month

At current level's fixed/variable split (56.19% / 43.81%), the calculated fixed charge of $39.77 is higher than the ceiling value of $22.76 and the existing approved fixed charge of $36.65.

Common approach: A distributor should propose to keep the fixed charge at the existing approved charge of $36.65

Revenue to Cost Ratio

Revenue Requirement Workform, Tab 11. Cost Allocation:

Revenue Requirement reflect adjusted revenue to cost ratios for GS < 50 kW, GS 50 to 4,999 kW and Sentinel Lighting rate classes.

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Street Lighting	86.60%	89.96%	89.96%	80 - 120
Unmetered Scattered Load	116.80%	101.54%	101.54%	80 - 120

Sometimes, the increase in revenue requirement is phased in – as is the case with Sentinel Lighting

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2024	2025	2026	
1	Residential	103.45%	103.45%	103.45%	85 - 115
2	General Service < 50 kW	116.60%	116.60%	116.60%	80 - 120
3	General Service 50 to 4,999 kW	80.00%	80.00%	80.00%	80 - 120
4	Sentinel Lighting	71.34%	75.67%	80.00%	80 - 120
5	Street Lighting	89.96%	89.96%	89.96%	80 - 120
6	Unmetered Scattered Load	101.54%	101.54%	101.54%	80 - 120

Revenue to Cost Ratio

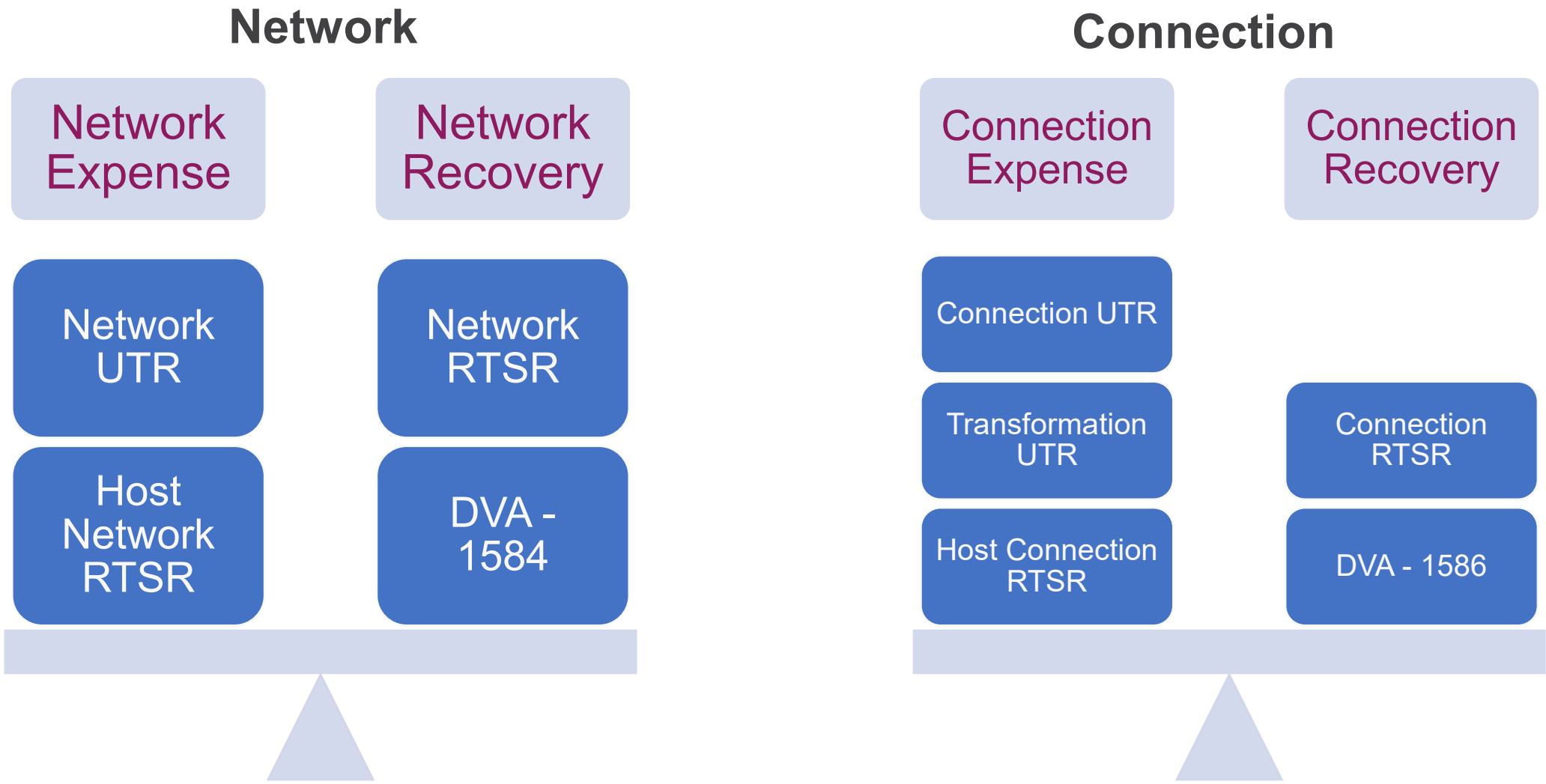
Revenue Requirement To Cost Adjustment Workform:

Implementation of phase-in over up-to 5 years.

Direction	Current Year	Transition Year 1	Transition Year 2	Transition Year 3	Transition Year 4	Transition Year 5
	2024	2025	2026	2027	2028	2029
No Change	103.45%	103.45%	103.45%	103.45%	103.45%	103.45%
No Change	116.60%	116.60%	116.60%	116.60%	116.60%	116.60%
No Change	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
Change	71.34%	75.67%	80.00%	80.00%	80.00%	80.00%
No Change	89.96%	89.96%	89.96%	89.96%	89.96%	89.96%
No Change	101.54%	101.54%	101.54%	101.54%	101.54%	101.54%

Typically, an offsetting adjustment is made to a second rate-class. The required adjustments are sourced from the approved rebasing proceeding.

Background – Transmission Charges



RTSR updates

Volume Entry

- Sheet 3:
  - Most recent historic RRR retail volumes
- Sheet 5:
  - Most recent historic wholesale volumes

Rate Entry

- Sheet 4:
  - Best: Approved Test Year rates if available
  - Otherwise: Preliminary test year UTRs and Hydro One RTSRs, if available
  - Otherwise: Current approved rates.

EV Charging Rates

- EV rate parameter, and EV charging rates added to the model for all GS 50 – 5,000 kW rate classes in 2026
- Rate is mandatory for distributors to make available to their charging customers, but opt-in for customers
  - If possible, please estimate the EV charging load, but either way, the model will produce an appropriate rate

Low Voltage Background

Low Voltage

- Some distributors receive some or all their supply from other distributors
  - In this instance, the distributor must pay distribution charges to its host distributor.
  - Low Voltage charges are used to recover the cost of procuring distribution service from a host.
  - Hydro One is the most frequent host distributor, although several others exist

Characteristics of Low Voltage

- LV points, by their nature are typically lower volume than full Transmission connections
  - Most frequently used by very small utilities, or immaterially used by larger utilities
  - Embedded points are typically at service territory boundaries

Low Voltage Practice

Host Distribution Expense

- A variety of approaches have been used
  - Historic average of host billing
  - Historic average of host volume
- Preferred approach is to estimate test year volumes and multiply by the most current host rates.
  - Frequently, historic volume is the best estimate

Rate Derivation

- LV costs are allocated to rate classes on based on the allocation of RTSR Connection
- LV rates are set based on the same volumetric billing determinants

The NWS Guidelines and BCA Framework

Key Requirements

- *System planning:* Document consideration of NWS for capital investment decisions above a $2 million cost threshold.
  - *For capital investments above $2 million, LDCs should conduct a preassessment to identify whether there is a reasonable expectation that an NWS may be a viable option.*
  - *The degree of consideration given to NWSs should be proportional to the expected benefits and account for the size and resources of a distributor.*
- *Cost-effectiveness evaluation:* If an NWS is a viable option, apply the Benefit-Cost Analysis (BCA) Framework to assess whether an NWS or a traditional solution is the preferred option to address the system need.

Applicability to VSUs is likely very limited.

Overview of LRAMVA

Purpose

The Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) enables distributors to calculate and seek disposition of eligible lost revenues from Conservation and Demand Management (CDM) programs

IRM Application

- Distributors have disposed of outstanding LRAMVA balances related to previous CDM programs and should now have a zero balance in their LRAMVA.
- Some distributors had LRAM-eligible amounts approved for future years. The approved amounts are to be adjusted mechanistically by the approved inflation minus X factor applicable to IRM applications in effect for a given year and recovered through a rate rider.

Cost of Service Application

- Previously approved LRAM-eligible amounts do not continue into new rate term.
- Distributors may request the use of an LRAMVA for new distribution rate-funded non-wires solutions activities, with need to be determined on a case-by-case basis.

NWS, BCA, and LRAMVA Expectations of VSUs

Limited.

- OEB Staff believe NWSs are unlikely to be a reasonable alternative for most $2M+ investments VSUs might make.
    - As such, it is unlikely VSUs will need to complete a BCA.
- OEB Staff believe all VSUs have a zero LRAMVA balance.
- As part of a CoS application, distributors may **(but are not obligated to)** request the use of an LRAMVA for new distribution rate-funded non-wires solutions or eDSM/CDM activities.

Contact James Smith (James.Smith@oeb.ca) or Christopher Humphries (Christopher.Humphries@oeb.ca) for support.

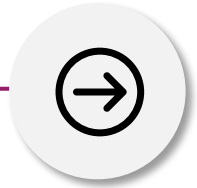
Incremental Capital Module / Advanced Capital Module

Incremental Capital Module (ICM)

- Funding mechanism to collect additional revenues to help with financing, until the subsequent rebasing application, on capital expenditures
- At rebasing, the capital asset is added to rate base at its net book value, based on actual costs and depreciation to date
- Rebasing application will review actual (audited) costs of ICM project

Advanced Capital Module (ACM)

- Allows a pre-review of potential future capital projects in the Distribution System Plan when rebasing, which may require additional capital during the IRM term
- Purpose is to confirm *need* so that the distributor has some certainty for its planning
- No funding in advance of the in-service
- Funding is confirmed in the IRM application when the asset is placed in service



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Thank you for attending!