TECHNICAL CONFERENCE UNDERTAKING - JT 4.1

JT 4.1

To provide a scenario where, first, the requested variables are removed and then any additional variables that are no longer statistically significant are also removed.

RESPONSE:

When the April binary was removed, and a constant added to the GS1000 share model, the November binary became statistically insignificant and was removed. All remaining variables are statistically significant. Variable coefficients and new predicted values can be found in Excel Attachment JT 4.1(A): Requested Load Forecast Scenario.

When the September binary was removed, and a constant added to the Street Lighting sales model, the April binary became statistically insignificant and was removed. All remaining variables are statistically significant. Variable coefficients and new predicted values can be found in the same Excel Attachment JT 4.1(A): Requested Load Forecast Scenario.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.2

JT 4.2

RE Staff 131A, attachment showing the model, tab GS 1,000 NI-CO-F, to explain how the model differs from a ratio of kilowatt-hours to kilowatts.

RESPONSE:

The specification suggested during the Technical Conference by OEB Staff was that, with the model containing only the megawatt-hour and December 2017 variables, this would essentially be a ratio of megawatt-hours to kilowatts. With this model specification, the adjusted r-squared would be 0.093, compared to 0.514 with the original model specification. The 12 monthly binaries are used in all demand models to capture variation in demand not explained by the megawatt-hour variable.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.3

JT 4.3

RE Staff 132, to provide a reference to load forecasting evidence which includes a derivation of the billing demand.

RESPONSE:

Table 8 from UPDATED Attachment 3-1-1(C): Hydro Ottawa Long-Term Electric Energy and Demand Forecast is incorrectly labeled as megawatts (MW). The correct unit label is kilowatts (kW). The values represent the annual maximums, with the highest of the 12 monthly values in each year, rather than the aggregate of the 12 monthly values.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.4

JT 4.4

RE Staff 138, to provide examples of where a 20-year average was accepted in Ontario, and to explain why Hydro Ottawa is proposing to use an average as opposed to a trend.

RESPONSE:

In Horizon Utilities Corporation' 2015-2019 Custom IR application forecast, a 20-year average was used to define normal weather.[1] PowerStream Inc. used a 10-year average to define normal weather in its 2016-2020 Custom IR application.[2] Neither filings used a trended normal. In addition, Hydro Ottawa's 2016-2020 approved forecast used a 20-year average to derive normal weather.

As indicated in the response to interrogatory OEB-138, according to a 2017 Itron survey, the 20-year average is the most commonly used and accepted method for defining normal weather in the industry.

[1] Horizon Utilities Corporation, *2015-2019 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2014-0002 (April 16, 2014).
[2] PowerStream Inc., *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0003 (May 22, 2015).

TECHNICAL CONFERENCE UNDERTAKING - JT 4.5

JT 4.5

To advise whether it was intentional that there is no apportionment for the deferred revenue or capital contribution or any of the amortization entries, be it accumulated or expense, and to correct it at the next opportunity to update the model.

RESPONSE:

The allocation of capital accounts 1835 and 1845 (gross capital) to primary and secondary drivers were updated by way of Attachment OEB-38(A): UPDATED Workform_CostAllocationModel_NewModel to be equal to the allocations in accounts 1830 and 1840, respectively. Apportionment of deferred revenue, capital contribution, and amortization for those accounts (1835 and 1845), however, remained at 100% allocation to primary.

Hydro Ottawa confirms that this was an oversight and agrees to update the Cost Allocation Model. Hydro Ottawa will update the Cost Allocation Model as part of its response to undertaking JT 3.1, which will be filed on August 5, 2020. The change will result in $74,000 being allocated from the Residential and Small Commercial classes.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.6

JT 4.6

To see if there is a large impact of doing the billing/scaling differently.

RESPONSE:

The undertaking asks for an assessment of the impact on Cost Allocation of scaling Standby demand factors on the basis of change in forecasted demand from Hydro Ottawa's 2016 rate application[1] to the 2021 rate application.

The net impact of the request is an increase in Standby demand data by a factor of 1.55. There is no impact on the demand data for other customer classes. The increase in demand for Standby results in an allocation of an additional $29K in costs to the Standby class, reducing its Revenue/Cost ratio from 36.6% to 25.4%. This change is offset by a slight increase to the Revenue/Cost ratios of the other customer classes.

Please see Table A below for the impact of changing the demand forecast methodology.

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

Table A – Impact of Changing Demand Forecast Methodology for Standby Customer Class

Customer Class	Revenue / Cost (%)		Revenue Requirement ($K)	
	Latest Filed (IRR OEB-38)	Revised Standby Demand	Latest Filed (IRR OEB-38)	Revised Standby Demand
Residential	100.20%	100.21%	$124,069	$124,060
GS < 50 kW	119.71%	119.72%	$22,334	$22,331
GS 50 to 1,499 kW	89.69%	89.71%	$51,004	$50,992
GS 1,500 to 4,999 kW	111.12%	111.15%	$9,902	$9,899
Large Use	90.82%	90.85%	$7,644	$7,642
Street Light	120.42%	120.43%	$1,028	$1,028
Sentinel	51.25%	51.25%	$10	$10
Unmetered Scattered Load	106.04%	106.05%	$587	$587
Standby Power GS 1,500 to 4,999 kW	36.62%	25.36%	$60	$89
			$216,638	*$216,638*

TECHNICAL CONFERENCE UNDERTAKING - JT 4.7

JT 4.7

To explain the part in 1 Staff 31 about understanding about accumulated depreciation netted to cost. Also to advise whether gross plant value or gross plant additions prior to 2014 will be restated or have they been restated, or is it the case that just going forward that the numbers will be different.

RESPONSE:

International Financial Reporting Standards 1 - *First-time adoption of International Financial Reporting Standards* (“IFRS 1”) allows first-time adopters certain exemptions from the retrospective application of certain IFRS standards. Accordingly, when an entity holds items of property, plant and equipment (“PP&E”) and intangible assets that are used in operations subject to rate regulation, and the carrying amount (accumulated depreciation netted to cost) of such items might include amounts that were determined under previous Generally Accepted Accounting Principles (“GAAP”) but do not qualify for capitalization in accordance with IFRS, IFRS allows a first-time adopter to use the previous GAAP carrying amount of such an item at the date of transition to IFRS as its deemed cost.

Hydro Ottawa elected to use the pre-changeover Canadian GAAP carrying amount of PP&E and intangible assets as deemed cost, at the date of transition to IFRS (January 1, 2014). Consequently, the gross plant value and gross plant addition prior to 2014 did not have to be restated, and the going forward numbers are accounted for in accordance with IFRS.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.8

JT 4.8

To advise whether, for a given year's new additions to rate base, does the main impact on the revenue requirement typically occur in the second year due to tax considerations.

RESPONSE:

The main impact on the revenue requirement for new additions to rate base does typically occur in the second and later years, because only half of the new capital additions are added to rate base in the first year.

As well, and as outlined in UPDATED Exhibit 4-4-1: Payments in Lieu of Taxes, Bill C-97 has put in place temporary rules for Capital Cost Allowance ("CCA") deductions which allow for both a full deduction of the CCA (versus the normal ½ year rule) as well as an accelerated CCA rate in the first year for eligible additions. During their years of availability, these new tax rules will also minimize the impact of the overall revenue requirement in the first year of a capital addition.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.9

JT 4.9

Re 1-staff-33, to provide data prior to 2012 and as many years as are available.

RESPONSE:

Table A provides a summary of Hydro Ottawa's targeted and actual return on equity ("ROE") for the 2008-2019 period.

Table A – 2008-2019 Targeted and Actual ROE[1]

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ROE Approved	8.57%	8.57%	8.57%	8.57%	9.42%	9.42%	9.42%	9.42%	9.19%	9.19%	9.19%	8.98%
ROE RRR[2]	9.50%	10.30%	8.80%	7.86%	9.41%	7.80%	8.06%	7.92%	9.80%	10.10%	9.14%	8.82%

[1] Rates prior to 2012 were effective on May 1 of each year.
[2] Please see the response to undertaking JT 3.9 for ROE used in the Earnings Sharing Mechanism calculation.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.10

JT 4.10

To respond to 1-staff-35 part b.

RESPONSE:

Hydro Ottawa began inputting asset age consistently for most assets in 2008 when its Geographic Information System ("GIS") went live. Gaps have been filled in with data from as-builts and inspection programs. The exception to this is distribution transformers, where Hydro Ottawa was able to upload purchase dates for the units from other sources, which provides a more complete and reliable picture of the units' ages.

Hydro Ottawa currently has age demographics for approximately 82% of assets in the GIS. Some asset types have much more information available, such as distribution transformers which have 99% available data. This is in contrast to overhead switches, which have 30% available data.

Hydro Ottawa does not conduct inventories on the assets, as the utility has now recorded all historical information on asset age that is available. Records in GIS are continuously maintained and updated from the initial input of construction proposals and through information received on as-builts, construction verification certificates, energization notifications, maintenance programs, and staff in the field. Ongoing updates include (but are not limited to) date of installation, equipment ratings, maintenance activity, and replacement dates/details.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.11

JT 4.11

With reference to technical conference transcript of Friday, July 17, 2020, page 94, to advise whether a report on an enquiry into the rate-setting options is available, and if so, to file.

RESPONSE:

Please refer to Attachment JT 4.11(A): RASC Meeting - October 9, 2018 for an abridged version of the presentation that was delivered to Hydro Ottawa's Rate Application Steering Committee ("RASC") on October 9, 2018. This presentation reviewed rate-setting options available to, and considered by, Hydro Ottawa.

Rate Application Steering Committee Meeting

Preparing for the 2021-25 Rate Application

(Abridged to respond to
Transcript Undertaking JT – 4-11)

October 9th, 2018

Regulatory Affairs

Agenda

1. Introduction
2. Status of Preparations
3. Draft Rate Case Strategy
4. Rate Options
5. Key Decisions Required
6. Next Steps

Introduction

- Big lift coming up
- Need support across the company
- Support to date has been great – thank you!
- We have a plan – we will ‘work the plan’
- Good progress has already been made

Status of Preparations

Key Items:

- Draft Rate Case Strategy Developed (*see next slide*)
- Detailed schedule developed
- Special Studies identified and confirmed with Chiefs
- Customer Engagement Plans being developed
- Benchmarking studies still need to be confirmed
- Strategic Planning, Budgeting & Rate Planning Aligned
- Rate Application Working Group (RAWG) formed and has meet three times
- Draft Table of Contents for key pieces of evidence (e.g. Productivity, HOL Business Plan, Facilities) being developed
- Research being conducted re: relevant information and experiences from other LDC rate applications
- Initial identification of witnesses
- Many meetings held with staff – awareness is good
- Rate Application Common SharePoint site established (moving to AODOC's)

Draft Rate Case Strategy

Strategy

- Ensure the application is guided by the HOHI Corporate Strategic Direction.
- Demonstrate HOL's focus on the customer including meaningful customer engagement and the incorporation of customer feedback
- Prepare the rate application in a manner that shows adherence to the directions contained in the OEB's RRF, Filing Guidelines and Directives.
- Demonstrate that the capital and OM&A work programs put forward are well planned and cost effective and take into account the rate impacts on the various customer classes.

Key Objectives

- Ensure that HOL's approved revenues in the period 2021 to 2025 are sufficient to maintain public & employee safety, system reliability & financial soundness while delivering customer value
- Obtain approvals for submitted OM&A and CAPEX work program levels.
- Obtain approval of the full new facilities project expenditures.
- Demonstrate that HOL is well-managed & has effective governance practices & processes in place that result in sound decision making which reflects customer preferences.

Rate Options

Two main options:

1. Custom Incentive Regulatory (CIR) Application
2. Price Cap / IRM Application

Rationale for Custom Incentive Regulatory (CIR) Rates Application

- A CIR approach provides financial and planning stability for a five year period
- Preparing a CIR is not much more work than preparing a Price Cap / IRM where a Cost of Service application would have to be filed for 2021
- Under certain assumptions a CIR approach will yield $10m more in revenues over the 2021-25 period when compared to a Price Cap / IRM application
- However a CIR approach could be more problematic if the regulatory rules change significantly over the next few years
- Regardless of which approach selected a ‘heavy lift’ for HOL is required over the next two years

Key Decisions

Required Today or Very Soon

- What level of rate increase are we willing to ask for?
- Filing a Custom Incentive Regulatory (CIR) Application vs. moving to a Price Cap / IRM Application
- Asset Needs Forecast and approach to rationalize CAPEX

Required Later

- Incentive regulatory mechanism(s) for OM&A and CAPEX
- Depth of evidence vs. interrogatory load
- Settlement Conference Strategy
- Preparing for an oral hearing on entire rate application

HydroOttawa

Next Steps

- Monitor the status of the special studies & benchmarking reports
- Hold a larger staff meeting to provide an update on overall preparations and ensure common understanding & messaging
- Continue to work through the RAWG to develop detailed outlines for key pieces of evidence including;
  - Productivity Exhibit
  - Facilities Evidence
  - HOL Business Plan
- Continue movement to AODOC's as the document management platform & associated training

Rate Application Planning Process
Schedule

Date	Event
Spring 2018	Identify required Special Studies & Benchmarking
Summer 2018	Form Regulatory Affairs Steering Committee (RASC)
Fall 2018	Customer Engagement on Distribution System Plan (DSP)
Winter 2019	Special Studies & Benchmarking Reports completed
Winter 2019	Updated DSP Completed
Spring 2019	Planning Process to support Rate Application Starts
Summer 2019	Evidence Preparation Starts
Summer 2019	Customer Engagement(s) on Application
Fall 2019	HOL Business Plan approved by HOL and HOHI Boards
Fall 2019	Evidence is finalized
Fall 2019	Rate Application approved by HOL and HONI Boards
December 2019	**Rate Application Filed**
Winter 2020	HOL Presentation(s) / OEB Community Meeting(s)
Spring 2020	Interrogatory process
Summer 2020	Technical and Settlement Conferences
Fall 2020	Oral Hearing
December 2020	OEB Decision
January 1, 2021	Rates implemented

Questions or Comments?

TECHNICAL CONFERENCE UNDERTAKING - JT 4.12

JT 4.12

Re exhibit 2, tab 4, schedule 1, page 15, line 25, the variance between the approved and actual in-service additions for the general plant category, to provide a breakdown of the $14 million.

RESPONSE:

The $14.0M variance between the approved and actual in-service additions for the General Plant category in the 2016-2020 period can be broken down as follows:

- True-up Connection Cost Recovery Agreement (“CCRA”) payments to Hydro One Networks - $7.1M;
- Change in Enterprise Resource Planning (“ERP”) upgrade, with the Human Resources Module completed using Workday and integrated with JD Edwards - $4.4M; and
- Remaining variance is attributable to a number of other smaller projects.

TECHNICAL CONFERENCE UNDERTAKING - JT 4.13

JT 4.13

To rank who is the hilliest to the least hilly.

RESPONSE:

Table A provides a ranking of the utilities that were included in the peer group for the total cost and reliability benchmarking study prepared by Clearspring Energy Advisors, which was included in the pre-filed evidence as Attachment 1-1-12(A) in this proceeding. The utilities are ranked by Highest Hilliness to Lowest Hilliness. Ontario utilities are marked in bolded text.

Table A – Ranking of Total Cost & Reliability Benchmarking Study Sample of Utilities by Standard Deviation of Elevation

Utility	Standard Deviation of Elevation Rank
Southern California Edison Company	1 (Highest Hilliness)
Public Service Company of Colorado	2
Pacific Gas and Electric Company	3
Arizona Public Service Company	4
Puget Sound Energy, Inc.	5
San Diego Gas & Electric Co.	6
Nevada Power Company	7
Idaho Power Co.	8
Portland General Electric Company	9
Duke Energy Carolinas, LLC	10
Monongahela Power Company	11
Avista Corporation	12
Appalachian Power Company	13
Black Hills Power, Inc.	14
Tucson Electric Power Company	15
Central Hudson Gas & Electric Corporation	16
Public Service Company of New Hampshire	17

Utility	Standard Deviation of Elevation Rank
Kentucky Utilities Company	18
Niagara Mohawk Power Corporation	19
Duke Energy Progress, LLC	20
Western Massachusetts Electric Company	21
New York State Electric & Gas Corporation	22
Central Maine Power Company	23
Virginia Electric and Power Company	24
PPL Electric Utilities Corporation	25
Public Service Company of Oklahoma	26
El Paso Electric Company	27
West Penn Power Company	28
Hydro One Networks Inc.	29
Pennsylvania Electric Company	30
Southwestern Public Service Company	31
Wisconsin Public Service Corporation	32
Orange and Rockland Utilities, Inc.	33
Kansas Gas and Electric Company	34
Jersey Central Power & Light Company	35
Wisconsin Electric Power Company	36
Connecticut Light and Power Company	37
Kentucky Power Company	38
Entergy Arkansas, Inc.	39
Oklahoma Gas and Electric Company	40
Metropolitan Edison Company	41
Northern States Power Company - WI	42
Northern States Power Company - MN	43
Alabama Power Company	44
Baltimore Gas and Electric Company	45
Union Electric Company	46
Cleveland Electric Illuminating Company	47
Consumers Energy Company	48

Utility	Standard Deviation of Elevation Rank
Consolidated Edison Company of New York, Inc.	49
Toronto Hydro-Electric System Limited	50
South Carolina Electric & Gas Co.	51
Duke Energy Indiana, LLC	52
Empire District Electric Company	53
PECO Energy Company	54
Ohio Edison Company	55
ALLETE (Minnesota Power)	56
United Illuminating Company	57
Wisconsin Power and Light Company	58
Alectra Utilities Corporation	59
Pennsylvania Power Company	60
Mississippi Power Company	61
Potomac Electric Power Company	62
Duquesne Light Company	63
Duke Energy Kentucky, Inc.	64
Duke Energy Ohio, Inc.	65
Kansas City Power & Light Company	66
Louisville Gas and Electric Company	67
Entergy Mississippi, Inc.	68
Commonwealth Edison Company	69
Public Service Electric and Gas Company	70
Delmarva Power & Light Company	71
Northern Indiana Public Service Company	72
Cleco Power LLC	73
Madison Gas and Electric Company	74
Indiana Michigan Power Company	75
Kitchener-Wilmot Hydro Inc.	76
Toledo Edison Company	77
Indianapolis Power & Light Company	78
Hydro Ottawa Limited	79

Utility	Standard Deviation of Elevation Rank
Southern Indiana Gas and Electric Company, Inc.	80
Gulf Power Company	81
Atlantic City Electric Company	82
Duke Energy Florida, LLC	83
Tampa Electric Company	84
London Hydro Inc.	85
Florida Power & Light Company	86
EnWin Utilities Ltd.	87
Entergy New Orleans, Inc.	88 (Lowest Hilliness)

TECHNICAL CONFERENCE UNDERTAKING - JT 4.14

JT 4.14

To explain the theoretical basis behind the extreme weather variables in the models.

RESPONSE:

The heating degree days ("HDD") variable that measures extreme cold weather had a negative coefficient sign when estimated separate from the cooling degree day ("CDD") variable. A negative coefficient sign does not align with the *a priori* theory that extremely cold temperatures will increase total costs.

It may be helpful to note that inclusion or exclusion of the extreme weather variable does not have a large impact on Hydro Ottawa's total cost results. If the Clearspring model excludes the extreme weather variable or if it only includes the CDD variable, the benchmarking score for Hydro Ottawa increases (worsens) by about 1% during the Custom IR period of 2021-2025. For example, in the case of only including the CDD variable, the Clearspring results would have yielded a score of -6.2% for Hydro Ottawa from 2021-2025, meaning that the utility's total costs are 6.2% below the expected benchmarks during the Custom IR period. This would continue to indicate a stretch factor of 0.3%.