Cost of Service orientation Q&A

Role of the registrar

Q: For the Procedural Order 1 timeline, is it 35 business days?
A: It is 35 calendar days.

Q: Since the OEB's performance standard calls for 230 days to render a decision, there is concern that a filer who submits in August won't get a rate order for new rates on time for May 1.
A: Under the 230-day schedule, an application filed in August 2019, will have a decision by April 2020. However, it should also be noted that the 230-day schedule reflects procedural steps that do not always occur in every case, including an oral hearing. You can review the full 230-day schedule of the OEB's website:
https://www.oeb.ca/sites/default/files/rates_cost_based_less_than_500M_20190311.pdf

Q: What is the status of community meetings?
A: It is not expected that 2020 filers will hold community meetings. The requirements to do so have been taken out of the filing requirements.

Filing requirements

Q: What is the plain language summary?
A: The OEB expects a 1 to 2-page summary in plain language that can be published on the OEB and utility's website. This is meant to inform customers of the utility's requests and provide them with a description of its impacts on customer bills.

Q: Is it still the intent to update the Distribution System Plan (DSP) metric on the scorecard?
A: It's still the intent; as part of the 2019-2020 Business Plan, the OEB will evaluate the current scorecard and assess possible modifications.

Q: Can you elaborate on what the OEB expects to see for capital project alternatives?
A: Examples in DSPs in which a utility has provided capital project alternatives are in Hydro One's EB-2017-0049 application (Mobile Unit Substation Program, Distribution Station Refurbishment, Pole Replacement Program, and Distribution Lines Sustainment Initiatives), and Alectra's EB-2017-0024 application, Alectra Utilities – Enersource DSP (York MS, Glen Erin & Montevideo – Section 1, and Derry Rd – Winston Churchill Blvd to Argentia)

Q: There was concern about customer engagement. Customers cannot be forced to engage; this particular utility has had open houses where only 1 or 2 people showed up. It's a real challenge to get people to engage. From their experience, customers are confused as to why utilities are asking them about the DSP for example; customers think it should be up to the utility to make the proper decisions.

A: Any feedback from customers is helpful. Technical questions may be difficult, but the OEB has seen helpful feedback from customers in relation to reliability issues and bill impacts—topics which they can understand.

Q: Concern from a small utility that scrutinizing asset conditions in detail is a significant investment for a small LDC to engage in.
A: In terms of asset management and planning, even for small utilities, there should to be some sort of assessment (visual assessment, asset age, testing, etc.) which determines when the utility replaces its assets.

Q: Is the OEB using third parties to review DSPs?
A: Yes, the OEB continues to use third-party consultants to assist with the review of some DSPs. Other DSPs are reviewed internally by OEB staff.

<u>Intervenors' perspective</u>
Q:. How does the intervenor determine whether a utility's plan is actually driven by their customers? How much customer input is sufficient?
A: The key is to show that the utility has taken active steps to consider customers' feedback and opinions on the utility's business plans

Q: Would the intervenors accept confidential filings related to cybersecurity?
A: The intervenor recognizes the confidential nature of cybersecurity matters. The OEB's guideline on confidential filings would apply, but intervenors expect an LDC to provide some information to evaluate the request.

<u>Accounting matters</u>
Q: If we did not dispose of 2017 DVA balances due to concerns with the account balances, do we need to go back and apply the new accounting guidance to both years (2017 and 2018) when applying for disposition?
A: If you didn't dispose of the balances and there were concerns noted in the OEB's decision (e.g. accuracy issues), the OEB would generally expect the utility to apply the new accounting guidance to historical balances and the 2018 balance that have yet to be disposed.

Q: If there are utility-specific sub-accounts in 1508, will they be automatically populated in the DVA Continuity Schedule?
A: The total balance for the control Account 1508 will be populated from the RRR in the RRR column of the DVA Continuity Schedule, but the individual sub-accounts will not be populated. The utility will need to show a breakdown of all 1508 sub-accounts and reconcile that to the total control account balance from the RRR. The utility will still be able to manually input utility-specific sub-account balances in the DVA continuity schedule.

Q: When disposing of GA, if there has been different Non-RPP customers that transitioned between Class A and B in different years, will there be customer specific rate riders?
A: In the DVA continuity schedule, there is a tab that allocates a portion of the GA to transition customers and calculates a monthly payment amount to each transition customer.

Appendices and models

Q: GA modifier question – If you have customers in the same class, where some are eligible for the GA modifier and some are not eligible, can those customers be split to calculate the commodity charge for the eligible customer vs. non-eligible customers?
A: Appendix 2-Z requires historical consumption volumes of Non-RPP customers that are eligible for the GA modifier and not eligible for the GA modifier to calculate a forecast weighted average price for all customers. This is then used in the calculation to forecast total commodity expenses.

Q: Can filers for January 2021 use 2018 historical values for Appendix 2-Z if they file by April 2020?
A: Yes for the initial filing, but the utility will likely be required to file an update for actuals.

Q: For the models, can LDCs link the OEB models to their own data models? In particular the cost allocation model which requires a lot of data inputs and we want to ensure the data is consistent.
A: Yes, but we ask the LDC to break the links before a model is filed.

Q: Where can LDCs find the information required to complete the higher values and lower values; A(1) and A(2) in Appendix 2-R?
A: In preparing the invoices to bill LDCs, the IESO and host distributors rely on metered energy at the delivery point(s). LDCs are billed for the higher quantity which includes supply facility losses. The data relating to both the metered and billed energy are entered into the LDC's settlement systems. Therefore LDCs will need to query their settlement systems to determine the amount of energy they receive onto their system at the metering points, and the amount of energy they are billed for.

The metered energy is the lower value to be populated in A(2), the billed energy is the higher value to be populated in A(1). LDCs will need to ensure that all energy coming onto their system including that from the IESO, host distributors and embedded generators is reflected in rows A(1) and A(2) on Appendix 2-R.

CDM and LRAM changes

Q: Now that the IESO has centralized CDM and has changed its reporting (and utilities won't be receiving this information until later), how is the utility supposed to incorporate it into their DSP?

A: The OEB acknowledges this challenge. The utility should use its best effort and work with the best available information.

Q: Is a distributor required to file for recovery of lost revenue from its customers or can it forgo recovery?

A: The expectation is that a distributor will come forward with disposition of LRAMVA at the time of their cost of service filing and lost revenue will be trued-up with respect to the CDM adjustment in the load forecast. If the calculation results in a return to the utility, they may use their discretion to forego it.

Q: Is there an expectation that a utility must use a third party to do a calculation of the LRAM?

A: No, utility staff can do it internally.