Report on gains and losses from differences in load and production

prepared for the Ontario Energy Board by London Economics International LLC

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The COVID-19 pandemic has had widespread impacts on households and businesses across Ontario, with temporary lockdowns, continued physical distancing measures, and the economic consequences of the pandemic leading in many instances to unexpected changes to consumption, demand, and volumes (referred to as load in this report), with the impacts varying between utilities and customer types. For regulated utilities on the delivery side (gas distribution, electricity transmission, electricity distribution), this report presents an approach for estimating gains or losses in revenues due to these gains or losses in load, which at a high-level involves the following steps:

1. *gather forecast, actual, and historical load data;*
2. *compare load forecast against actual load;*
3. *perform weather normalization of actual load and estimate residual load; and*
4. *assess revenue impact and identify cost saving offsets (if any) to arrive at residual revenue impact.*

This approach is also adjusted to apply to differences in production at regulated production facilities as a result of changes to their expected operating status.

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List of acronyms

ACM	Advanced Capital Module
CDD	Cooling Degree Days
COS	Cost of Service
DA	Deferral Account
g factor	Growth factor
HDD	Heating Degree Days
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
IR	Incentive Rate-setting
kW	Kilowatt
kWh	Kilowatt hour
LEI	London Economics International LLC
MWh	Megawatt hour
OEB	Ontario Energy Board
OM&A	Operations, Maintenance, and Administration
OPG	Ontario Power Generation Inc.
TVM	Time Value of Money

1 Executive summary

London Economics International LLC ("LEI") was engaged by the Ontario Energy Board ("OEB") to assist in its Consultation on the Deferral Account ("DA") – Impacts Arising from the COVID-19 Emergency ("DA Consultation"). As part of this process, LEI has prepared this report to provide an approach for estimating the value of gains or losses in revenues due to gains or losses in load that can be attributed to the COVID-19 pandemic for regulated utilities on the delivery side (gas distribution, electricity transmission, electricity distribution). In the context of this report, load refers to demand, consumption, and volumes. In addition, this report also provides an approach to estimate gains or losses in revenues due to gains or losses in production that can be attributed to the COVID-19 pandemic for regulated production facilities (i.e., electricity generation from Ontario Power Generation Inc.'s ("OPG") prescribed hydroelectric and nuclear generation assets).

The intention of this approach is to isolate reasonably identifiable gains or losses in load or production, relying where possible on methods and practices that utilities are already familiar with in the regulatory context, and in a manner which is intelligible to stakeholders. Such calculations are by their nature imprecise, and may or may not capture all the effects of COVID-19, or exclude all non-COVID related impacts.

The proposed approach for regulated utilities on the delivery side (covered in Section 2) uses a four-step process, as summarized in Figure 1.[1] The approach isolates a residual load value that will be applied to rates (specifically, rates that were current at the time of potential load impacts) to arrive at an estimate of the revenue impact. Potential savings (or costs), if any, are then netted out of this amount to arrive at a residual revenue impact.[2] As mentioned later in Section 2, it is important for utilities to assess load data at granular levels, which include rate class and zone-level assessments where relevant.

While the goal for regulated production is the same, as causal linkages are more direct, a separate and more simplified approach is covered in Section 3, which involves:

(i) identifying the impact the pandemic had on the operating status of regulated generating assets;

(ii) determining the resulting regulated net gains or losses in production at the asset-level; and

(iii) establishing the net impact on revenues attributable to these gains or losses in production, net of any incremental costs and expenses directly associated with these

[1] Steps 1, 3, and 4 are relevant for the purposes of arriving at the value for residual revenue losses or gains as a result of losses in load. However, LEI believes Step 2 is important in establishing if the utility's actual load was impacted in some material fashion, before moving on to establishing if that impact was due to weather effects.

[2] Provided these savings/costs are not accounted for in any DA sub-account. For reference, the DA sub-accounts are discussed in further detail in LEI's separate report on regulatory responses to COVID-19 in other jurisdictions entitled "A report on regulatory principles, policies, and accounting treatments applied in other jurisdictions in response to COVID-19."

gains or losses in production (provided these costs and expenses are not accounted for in any DA sub-account or through some other avenue).

Figure 1. Approach to estimating gains or losses in revenues due to differences in load

1 Gather forecast, actual, and historical load data

Start with weather-normalized load forecast approved by the OEB in most recent rebasing or Custom IR application, adjusted by a growth ("g") factor to arrive at an adjusted load forecast for 2020 (by rate class and rate zone level where relevant, which should be the case for all load-related steps)

Gather 10-year historical load data (2010-2019), calculate standard deviation based on this data. Add and subtract this standard deviation from adjusted load forecast for 2020 to arrive at upper and lower bounds of reasonableness

2 Compare adjusted forecast load against actual load

Compare adjusted 2020 load forecast and the bounds of reasonableness established in Step 1 against actual load for 2020, to establish if actual load has deviated in some material fashion from forecast (regardless of cause)

3 Perform weather normalization of actual load and estimate residual load

Weather-normalize 2020 actual load to arrive at an estimate for 2020 actual load under normal weather conditions. Compare against bounds to isolate residual load deviation (if any)

4 Assess revenue impact

Using residual load deviation and rates that were current at the time, estimate the revenue impact value. Sum revenue impacts across all rate classes and rate zones to arrive at aggerate revenue impact amount

Identify potential savings and/or costs (if any) that emerged as a result of the residual gains or losses in load, that are <u>not being recorded in any other DA sub-accounts</u>. Net these savings/costs out from aggregate revenue impact amounts to arrive at residual revenue impact

2 Estimating differences in revenues due to differences in load

This section outlines the approach for regulated utilities on the delivery side (natural gas distribution, electricity distribution, electricity transmission). As mentioned previously, "load" is used for terminological simplicity to refer demand, consumption, or volumes. **The actual and forecasted load data being discussed in this section should be assessed at the levels of granularity which ultimately determine the resulting revenue impact value**. For example, electricity and natural gas distribution utilities should assess load impacts at the customer rate class level, as well as by rate zone in instances where utilities have more than one.[3] In this regard, utilities can determine what class-level analysis will need to be conducted. For example, in the case of an electricity distribution utility, for rate classes that have entirely fixed billing determinants, no additional analysis on that specific rate class would be required, as revenue for the class is not impacted by changes in volumes delivered; similarly, if revenue for a rate class only depends on consumption, then demand for that rate class need not be assessed.

The period being assessed should commence from March 2020,[4] and recording of revenue amounts should continue until the utility's next rebasing, as the potential revenue impact is by no means guaranteed to end once the provincial emergency associated with the pandemic is lifted. In this regard, ripple effects may persist in the event that businesses continue to be impacted as stimulus programs are drawn down or commercial leases end. Given these uncertainties, this approach does not propose attempting to differentiate between load changes that may be temporary or permanent. Instead, the focus is on identifying a residual load value through the first three steps, followed by a residual revenue impact estimation in the fourth step. As load forecasts are inherently uncertain, and utilities are already compensated for certain degrees of risk through their current cost of capital parameters, the approach also outlines bounds around load variation from forecast which can be considered acceptable. The approach outlined below assumes one standard deviation around historical average loads to define the bounds, although a higher standard deviation (i.e. wider bounds) may be justifiable.

The overarching purpose of each step detailed in this section is summarized in Figure 2.

[3] This level of assessment will also aid in mitigating potential class-level and zonal cross-subsidization concerns.

[4] In line with when the potential implications of the pandemic may have started to emerge. For example, the Government of Ontario declared a provincial emergency on March 17, 2020.

Figure 2. Simplified steps along with purpose

Step 1: Gather forecast, actual, and historical load data
Purpose: To gather relevant starting information, including baseline forecast for 2020 load
Step 2: Compare adjusted forecast load against actual load
Purpose: To establish if actual load fell outside the bounds of forecasted load by one standard deviation
Step 3: Perform weather normalization of actual load and estimate residual load
Purpose: To establish if weather-normalized actual load fell outside the bounds of forecasted load by one standard deviation and arrive at residual estimate
Step 4: Assess revenue impact
Purpose: To calculate residual revenue impact

2.1 Step 1: Gather forecast, actual, and historical load data

As a first step, the utility should start with its weather-normalized load forecast approved by the OEB in its most recent rebasing[5] or Custom IR application, and maintain full consistency with the levels of granularity discussed at the start of this section. If a utility wishes to use a load forecast other than one approved by the OEB, then the onus would be on the utility to: (i) support why an alternative forecast is reasonable, and (ii) confirm that it is congruent with the revenue requirement recovered through current rates.

Once an appropriate weather-normalized load forecast is selected, utilities should then adjust it by a growth ("*g*") factor to arrive at an adjusted load forecast for 2020. This is preferred in place of using the load forecast as-is, as the *g* factor accounts for customer growth and the impacts of conservation efforts, and hence provides a means to update the forecast to make it more current. The textbox below describes the *g* factor for distribution utilities in greater detail, as well as the formula which may be used by utilities to calculate their adjusted 2020 load forecast.

[5] The most recent load forecast should be used even if the utility is under either the Price Cap/Revenue Cap IR (for electricity distributors and transmitters, and natural gas utilities) or Annual IR (for electricity distributors only) rate-setting option and has not rebased in a long time.

Growth factor to calculate adjusted 2020 load forecast

The growth, or *g*, factor is used in the materiality threshold calculations under both the Advanced Capital Module ("ACM") and the Incremental Capital Module ("ICM"), which apply to electricity distributors. Similar modules and growth factors exist for natural gas distributors.[6]

The *g* factor accounts for changes in economic demand between two time periods, and comprises of the following components for electricity distribution:

1. change in number of customers;
2. change in kilowatt hours ("kWh") of electricity consumption; and
3. change in kilowatts ("kW") of energy demand, for demand-billed customers.[7]

The change in each of these components is assessed based on the difference between values from (1) the most recent COS application, and (2) the last actuals. Growth is then calculated as the revenue-weighted average of the change in each of these components between these two time periods and is then annualized.

This average annual *g* factor can then be applied to the most recent OEB-approved load forecast to arrive at an adjusted 2020 load forecast by class. To do this, the load forecast for each customer class should be multiplied by $(1+g)^{n-1}$, where n is the number of years from the last rebasing.[8]

To estimate the bounds of reasonableness around its adjusted 2020 load forecast, using the past ten years of historical data for its own actual load (2010 to 2019), the utility should then calculate the standard deviation on a monthly basis. Adding and subtracting the monthly historical standard deviations from forecasted 2020 load will provide upper and lower bounds of reasonableness.

2.2 Step 2: Compare adjusted forecast load against actual load

The adjusted 2020 load forecast and the bounds of reasonableness established in Step 1 will first be used to compare against the utility's actual load in 2020. The purpose of this step is to establish if the utility's actual load has deviated in some material fashion from the adjusted 2020 forecast,

[6] For example, in a 2019 filing, Enbridge Gas Inc. stated that it uses the ICM mechanism and calculates the value of the growth factor as "the % difference in distribution revenues between the most current year and the base year. The revenues are calculated maintaining the base rate constant." (Source: Enbridge Gas Inc. *Exhibit I.EP.13 (Case EB-2018-0305).* April 25, 2019.)

[7] OEB. *New Policy Options for the Funding of Capital Investments: Supplemental Report (EB-2014-0219).* January 22, 2016.

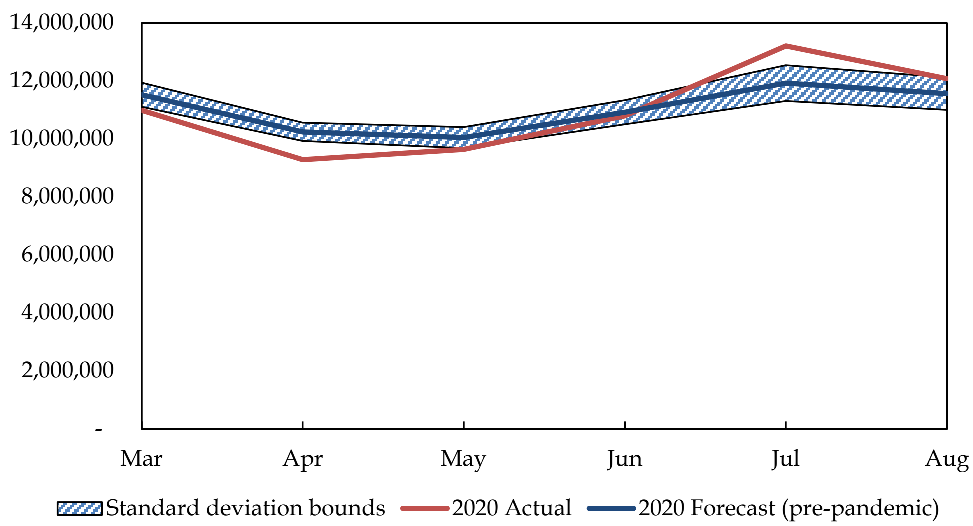
[8] This aligns with the approach used to calculate the materiality threshold value under the ACM and ICM. The general formula is included in Appendix B, *see* OEB. *New Policy Options for the Funding of Capital Investments: Supplemental Report (EB-2014-0219).* January 22, 2016.

regardless of the cause (e.g. the impact of COVID-19, weather effects, or other effects).[9] LEI views this as an important step in determining if there were actual load deviations from forecast first, before moving on to isolating out the weather effects in Step 3.[10]

A simplified example using Ontario system-wide electricity consumption data is presented in Figure 3. Actual consumption for the March to August 2020 timeframe is shown in the red line, along with the forecast for that same timeframe (blue line – with forecasts being conducted prior to the pandemic), and the upper and lower bounds based on one standard deviation of monthly historical data over the 2010-2019 timeframe (blue cross-hatch). On a system-wide level, electricity consumption fell outside these bounds most visibly in April due to the COVID-19 pandemic, while the increase in July was attributable to weather conditions.

It is important to note that this information is presented for illustrative purposes only, and is not meant to represent the load impacts seen at the utility level, nor does it represent gas consumption patterns. Some utilities would have seen larger declines in load (e.g. electricity distributors with high proportions of commercial load), while some utilities may have seen increases in load, and others may have seen little to no impact.

Figure 3. Illustrative actual, forecast, and bounds for system-wide monthly electricity consumption (2020)



Note: IESO data presented for illustrative purposes only. Full set of data for months after August were not available. IESO's 2020 forecast data is the average of its last three forecasts, and therefore may be capturing older information.

Sources: LEI analysis using IESO's 'Ontario and Market Demand' data and IESO's Q3 2020 Reliability Outlook data tables.

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[9] For example, actual load may remain within the bounds if a utility saw load declines for a certain customer class due to COVID-19 pandemic that were offset by load increases for that same class due to extreme weather events.

[10] While Step 2 is included in the report to provide clarity and understanding of the proposed approach, utilities in their implementation of the approach would likely skip from Step 1 to Step 3 (as Step 3 is the basis for determining the load deviation impact used to estimate the revenue impact).

Regardless of the outcome from Step 2, utilities should move on to the next step.

2.3 Step 3: Perform weather normalization of actual load and estimate residual load

As a third step, utilities should perform weather normalization on actual 2020 load to arrive at estimates for actual 2020 load under normal weather conditions. Utilities may rely on the OEB-approved weather normalization procedures used as part of their last rebasing (same filing as referenced in Step 1) to produce weather-normalized 2020 data. For reference, the textbox below discusses weather normalization in the regulatory context for Ontario LDCs; a weather normalization methodology is also required for natural gas utilities under Exhibit 3 (Operating Revenue) of their rate applications,[11] and for electric transmission utilities under Exhibit 5 (Operating Revenue).[12]

Weather normalization approaches for Ontario electricity distributors

According to the OEB's Handbook for Utility Rate Applications, weather normalization is defined as follows:

> "Weather normalization is a mathematical adjustment to past energy usage data. This adjustment removes the impact of annual variations in weather to show what the usage would have been under normal (or long term trend) weather conditions. Utilities weather normalize data to better understand how other variables, such as energy efficiency, price, building structures and new technology impact demand. This helps utilities understand trends in energy consumption and develop more reliable forecasts."[13]

As per Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, utilities are required to develop a weather normalization methodology as part of Exhibit 3 (Operating Revenue) in their cost of service ("COS") filing. The OEB enables each utility to propose a methodology instead of issuing a generic approach to apply to all utilities, as "[g]eneric load profiles and universal normalization methods may not reflect the unique customer mix, weather and economic activities of a utility's service territory."[14]

Nonetheless, the OEB sets out the following requirements for each utility's methodology. Within Exhibit 3 of the COS application, each utility using a multivariate regression model is to present its load forecast, as well as a weather-normalized load forecast based on:[15]

continued…

[11] OEB. *Filing Requirements for Natural Gas Rate Applications.* February 16, 2017.

[12] OEB. *Filing Requirements for Electricity Transmission Applications – Chapter 2: Revenue Requirement Applications.* February 11, 2016.

[13] OEB. *Handbook for Utility Rate Applications.* October 13, 2016.

[14] OEB. *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2: Cost of Service.* May 14, 2020. p. 23.

[15] Ibid.

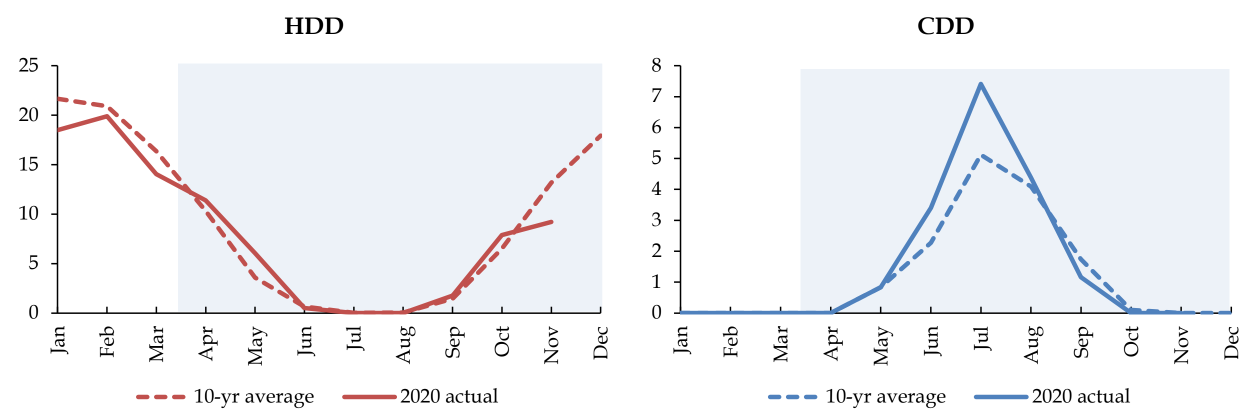
1. a 10-year average of the monthly heating degree days ("HDD") and/or cooling degree days ("CDD") used to determine normal weather; and
2. a trend based on 20-years of monthly HDD and/or CDD data.

As per the OEB's filing requirements, the utility is then to present a rationale to support the use of either numbered item (1) or (2) above; if an alternative approach is proposed by the utility, "it must be supported." Notably, HDD and CDD data for each utility is based on data from the weather station that is "appropriate for the distributor's service territory." Although these requirements relate to utilities' load forecasts, Appendix 2-IB of the COS filing requires utilities to include historical weather-normalized actuals.[16]

Ultimately, the OEB's COS filing requirements apply to utilities under the Price Cap IR rate-setting option (for those undergoing a COS filing), and guides utility filings under the Custom IR approach.[17]

For illustrative purposes, Figure 4 presents the average daily HDD and CDD by month for the Toronto City weather station over the 2010 to 2019 timeframe, along with the actual number of average HDD and CDD by month for 2020. The figure uses Environment and Natural Resources Canada data, which defines HDD for a given day as "the number of degrees Celsius that the mean temperature is below 18°C," and CDD for a given day as "the number of degrees Celsius that the mean temperature is above 18°C."[18] Based on this data, an above-average number of CDD were recorded in the summer months of 2020, which are likely to have driven up consumption over that period, disproportionately impacting summer-peaking electricity distribution utilities.

Figure 4. Average daily HDD and CDD by month for the Toronto City weather station



Sources: Environment and Natural Resources Canada's historical daily data for Toronto City weather station.

[16] OEB. *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2: Cost of Service.* May 14, 2020.

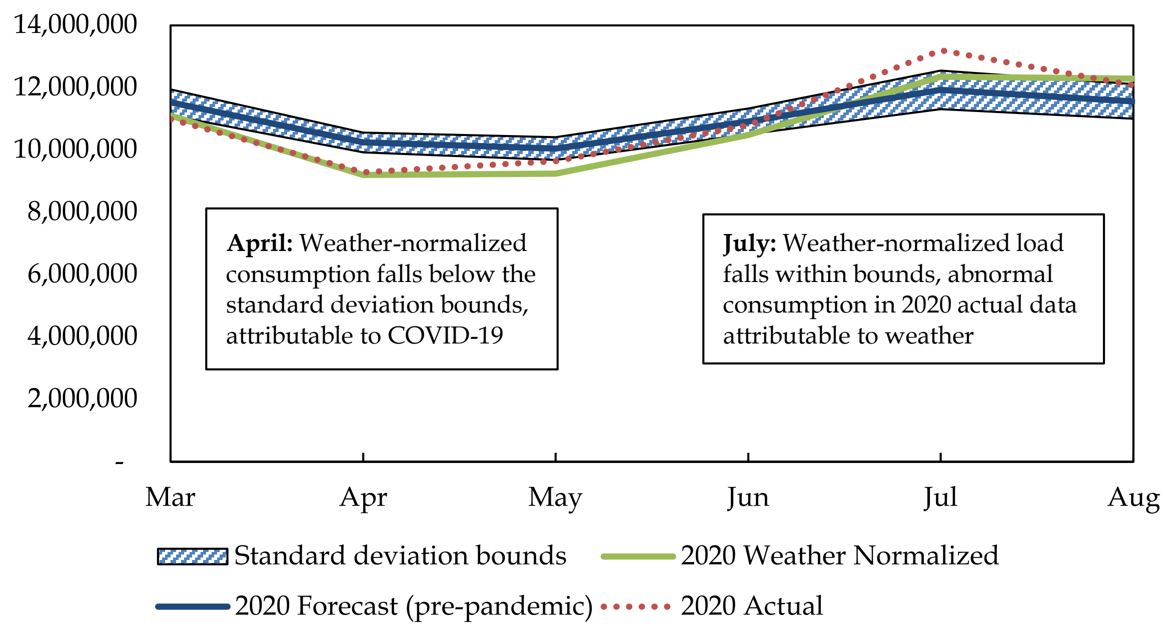
[17] Ibid.

[18] HDD and CDD are used primarily to estimate the heating and cooling requirements of buildings respectively. (Source: Environment Canada. *Glossary.*)

For further reference, using the same dataset from Figure 3, Figure 5 presents 2020 weather-normalized actual consumption (green line) and 2020 forecast consumption and standard deviation bounds (blue line and cross-hatch) from March to August. Also presented is the 2020 actual data, which is shown in the red dotted line. The difference between the 2020 actual and the 2020 weather-normalized lines (red and green) is the amount explained by weather effects, which had the most obvious effect in July for this data.

The difference between the 2020 weather-normalized data and the 2020 forecast (green line and bounds set by the blue lines) is the residual not explained by weather and outside the deviations from the forecast. This residual value thus isolates the load that is not explained by weather, which can either be negative (implying losses) or positive (implying gains), and is assumed to be attributable to abnormal load deviations due to COVID-19.[19] However, some individual utilities may have unique circumstances in which the COVID-19 pandemic and weather were not the only drivers for short-term load deviations from forecast. In these instances, the estimates for these non-COVID and non-weather effects should also be identified and netted out before arriving at the residual load deviation value.

Figure 5. Illustrative actual, forecast, and weather-normalized monthly electricity consumption (2020)



Note: IESO data presented for illustrative purposes only. Full set of data for months after August were not available. IESO's 2020 forecast data is the average of its last three forecasts, and therefore may be capturing older information.

Sources: IESO's Q3 2020 Reliability Outlook data tables.

[19] It is not appropriate to offset COVID-19 losses against gains from weather, as over time, gains from weather fluctuations offset periods when weather results in a loss. Only COVID-related gains and losses should be considered for the account.

If weather-normalized actual load deviated outside of the standard deviation bounds, the utility should arrive at the value for this residual load deviation, which will be the difference between the weather-normalized actual load and either the lower-bound around the forecast (when weather-normalized actual load is below the bounds), or the upper-bound around the forecast (when weather-normalized actual load is above the bounds).

2.4 Step 4: Assess revenue impact

The fourth step involves translating the residual load values established in Step 3 into revenue impact values, using the utility's rates that were current at the time the residual loss or gain in load occurred. As the previous steps were to be conducted at granular levels (including customer class and rate zone levels where relevant), to arrive at the associated revenue impact at the granular levels, the residual losses or gains in load should be multiplied against their associated rate classes or rate zones where relevant (based on the rates that were current at the time the residual load change occurred). These values should be recorded monthly and summed across classes to arrive at a total monthly revenue impact amount.

The utility should also identify any potential savings and/or costs that emerged as a result of the residual gains or losses in load, that are **not** being recorded in any other DA sub-accounts. Netting out the monthly savings/costs (if any) from monthly revenue impacts will provide a residual revenue impact.

2.5 Assessment against materiality threshold

While an assessment of materiality is important in the event that residual revenue impacts are identified, given utilities may be recording amounts in other DA sub-accounts, a single aggregate-level assessment of materiality (across all DA sub-accounts and related offsets) would be more appropriate than a load-specific materiality assessment. In this regard, materiality thresholds already established as part of filing requirements for applications may serve as a starting point, as summarized in the textbox below for reference.

Materiality thresholds for Ontario regulated utilities

Materiality thresholds from filing requirements for COS applications may be useful in assessing the overall materiality of amounts being recorded across the whole DA account. These thresholds are described below for each type of regulated utility.

<u>Electricity distributors:</u>

Under Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, the OEB lists materiality thresholds for annual changes to rate base, capital expenditures, and operations, maintenance, and administration ("OM&A") costs for utilities under a COS filing. These thresholds are designed "to ensure the OEB's review is focused on matters that are material" and depend on the magnitude of the utility's revenue requirement:

continued…

- distribution revenue requirement ≤ $10 million: the materiality threshold is $50,000;
- distribution revenue requirement > $10 million but ≤ $200 million: the materiality threshold is **0.5% of the distribution revenue requirement**; or
- distribution revenue requirement > $200 million: the materiality threshold is $1 million.[20]

Electricity transmitters: under Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications, the OEB lists the same materiality thresholds as those used for electricity distributors (see above), apart from the upper bound threshold. For transmitters with a transmission revenue requirement > $200 million, the materiality threshold is $3 million.[21]

Natural gas distributors: under the OEB's Filing Requirements for Natural Gas Rate Applications, the same materiality thresholds used for electricity distributors apply.[22]

OPG: under a December 2017 Decision and Order in Case EB-2016-0152, the OEB determined that a materiality threshold of $10 million is generally appropriate.[23]

[20] OEB. *Filing Requirements for Electricity Distribution Rate Applications – Chapter 2: Cost of Service.* May 14, 2020.

[21] OEB. *Filing Requirements for Electricity Transmission Applications – Chapter 2 Revenue Requirement Applications.* February 11, 2016.

[22] OEB. *Filing Requirements for Natural Gas Rate Applications.* February 16, 2017.

[23] OPG. *Decision and Order (EB-2016-0152).* December 28, 2017.

3 Process for regulated production

The approach discussed in Section 2 relates to regulated utilities on the delivery side. The goal for production (i.e., OPG's regulated nuclear and hydroelectric segments only) is the same – to establish the gains or losses in revenues due to gains or losses in regulated production attributable to the COVID-19 pandemic and its resulting consequences. However, as causal linkages and the resulting impacts on production are much more direct, a more simplified approach can be taken.

Therefore, the approach for OPG is as follows:

1) identify the impact of the pandemic on the operating status of regulated generating assets;

2) determine the regulated net gains or losses in production at the asset level as a result of the changes in operating status of those assets; and

3) establish the net impact on OPG's revenues as a result of these gains or losses in production, which is based on the revenues earned by the changes in production, net of any incremental costs and expenses directly associated with the gains or losses in production and revenue change.[24]

Based on OPG's recent financial reports, one example of the impact the COVID-19 pandemic has had on regulated asset production relates to the postponement of the start of Darlington Unit 3's refurbishment, which was expected to commence in the second half of May, but was deferred as a result of the pandemic.[25] Based on IESO generator output data, Darlington Unit 3 produced around 1.6 TWh between the second half of May and the end of July (when the unit was taken offline for a planned outage, with refurbishment activities commencing in early September).[26] For **illustrative purposes only**, Figure 6 presents the potential revenue gains associated with an increase to OPG's regulated nuclear production, assuming a delay in the refurbishment process commences mid-May, and further assuming the unit earned the regulated nuclear base price of $85/MWh. Under these assumptions, the gross revenue gain would be around $137 million. This gross revenue value does not take into account any incremental costs directly associated with the unit remaining online, which would need to be established in order to arrive at the net revenue impact.[27]

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[24] Provided these costs are not being recorded in any other DA sub-accounts, or provided these costs are not already being recovered through some other avenue.

[25] OPG. *2020 Second Quarter Results*. August 13, 2020.

[26] OPG. *2020 Third Quarter Results*. November 11, 2020.

[27] As mentioned in footnote 24, provided these costs are not being accounted for elsewhere.

Figure 6. Illustrative 2020 revenue impact from delay to Darlington Unit 3 refurbishment

Month	Gain in production (MWh)	Regulated nuclear price ($/MWh)	Associated revenue ($)
May	360,368	$85.00	$30,631,280
June	634,871	$85.00	$53,964,035
July	617,324	$85.00	$52,472,540
		Total	$137,067,855

Sources: LEI analysis based on regulated nuclear price in OPG's third quarter financial results, and Darlington Unit 3 output data from the IESO's Generator Output and Capability Reports.

The amount shown in Figure 6 is not meant to establish the impacts that OPG should record. The amount OPG actually records, if any, will depend on its own analysis of the amount of revenues attributable to the change in operating status of its regulated fleet as a result of the pandemic, net of incremental associated costs and expenses. In addition to the Darlington Unit 3 refurbishment deferral, other potential production changes attributable to the pandemic may include the deferral of the planned outage at Darlington Unit 1 "from the fall of 2020 to the following year [2021]"[28] as well as the slightly higher availability of regulated hydroelectric stations due to "overall slightly fewer outage days at the regulated hydroelectric facilities as the Company deferred certain planned maintenance and project activities in response to the onset of the COVID-19 pandemic in the second quarter of 2020."[29] Any other pandemic-related outages at regulated hydroelectric or nuclear stations should also be taken into account.

Broader questions and implications

In assessing the wider potential impact to ratepayers, considerations in later periods may provide for an offset or may provide for issues that need to be offset against. Returning to the Darlington Unit 3 example, the delay to the start of its refurbishment process means there will be a period of time in 2023/2024 when it was formerly anticipated to be running but where the unit may still be undergoing refurbishment as a result of this delay, leading to lower output in that time period. This leads to questions related to the time value of money ("TVM"), in that although the unit over-generated in 2020 compared to expectations prior to the pandemic, it will under-generate in the 2023/2024 period as a result of the delay; the TVM concept applies to the difference between receiving the less than three months of income this year versus in 2023/2024.[30]

continued…

[28] OPG. *2020 Second Quarter Results*. August 13, 2020.

[29] OPG. *2020 Third Quarter Results*. November 11, 2020.

[30] For example, all else being equal, and assuming a discount rate of 5%, the time-value of the illustrative gross revenue impact estimate from Figure 6 of $137 million in 2020 versus 2024 is around $24.3 million, and in 2020 versus 2023 is around $18.6 million.

A broader question relates to how these timeline shifts impact revenue requirements and nuclear production forecasts, as well as the potential for capital expenditures to increase as a result of schedule changes attributable to the pandemic, and the associated rate impacts.

Therefore, while the COVID-19 deferral account may serve as an interim means for recording the impact of gains or losses in revenues due to changes in production caused by the pandemic, these broader questions and wider implications should be considered at OPG's next rebasing, if not addressed earlier.

4 Appendix: List of works cited

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