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

BY EMAIL

June 16, 2026

Ritchie Murray
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Mr. Murray:

Re: Ontario Power Generation Inc. and DNNP LP (the Applicants)
2027-2031 Payment Amounts Application
Interrogatory Responses for OEB Staff Evidence
OEB File Number: EB-2025-0297

In accordance with Procedural Order No. 2 issued on March 4, 2026, please find attached responses to the interrogatories regarding the OEB staff sponsored evidence that was filed May 26, 2026. These responses are labelled as Exhibit N. All the responses that accompany this letter were prepared by the authors of the respective reports.

Response to M3-OPG-006, part a)

OEB staff is providing an additional response to interrogatory M3-OPG-006 part a), which was filed as follows:

a) Did OEB Staff ask CAEC to develop an alternative econometric model in place of ScottMadden's model for determining Darlington's normalized TGC/MWh and resulting stretch factor?
   i. Please provide a copy of the specific instructions received from OEB Staff and explain how CAEC responded to these instructions.

OEB staff did not ask Christensen Associates Energy Consulting to develop an alternative econometric model with respect to Total Generation Cost (TGC) or the associated TGC/MWh metric.

Request for Confidentiality

Pursuant to Appendix B of the Practice Direction on Confidential Filings, OEB staff is requesting confidential treatment of certain information included in the response to M3-OPG-007 part d). The redacted portion of the response describes the underlying dataset of ScottMadden, a consultant retained by the Applicants. OEB staff notes that the Applicants have requested confidential treatment of the same underlying data as part of their April 30, 2026 request for confidential treatment of L-A1-Staff-002 Attachment 19.

Individuals who have signed a Declaration and Undertaking may access the unredacted version of Exhibit N by contacting the Registrar.

Please direct any questions relating to these filed documents to the Case Managers, Thomas Eminowicz, at Thomas.Eminowicz@oeb.ca and Jeffrey Sauer, at Jeffrey.Sauer@oeb.ca.

Yours truly,

Thomas Eminowicz Digitally signed by Thomas Eminowicz Date: 2026.06.16 16:30:39 -04'00'

Jeffrey Sauer Jeffrey Sauer 2026.06.16 16:29:39 -04'00'

Thomas Eminowicz
Senior Advisor,
Electricity Supply

Jeffrey Sauer
Senior Advisor,
Electricity Supply

Cc: All parties in EB-2025-0297
Encl. Exhibit N, Responses to Interrogatories

Ontario Power Generation Interrogatory #M1-OPG-001

Interrogatory

Reference:

Exhibit M1

Question(s):

Please provide a complete list of all proceedings in which the CAEC cost of capital witnesses in this proceeding have provided expert evidence, testimony, or reports on utility cost of capital or capital structure, including:

a) CAEC witness;
b) the docket number and jurisdiction;
c) the name of the utility or regulated entity;
d) whether the evidence related to ROE, equity thickness, or both;
e) the final decision date; and
f) the final approved equity ratio and ROE, if any.

Please include copies of the relevant testimony, reports, and final decisions, or provide precise citations to where they are publicly available.

Response:

The following response is provided by CA Energy Consulting.

Mr. Crowley has provided testimony in the following proceedings.

1. Jurisdiction: Florida
    a. Docket: 20240099-EI
    b. Client: Florida Public Utilities
    c. Subject: ROE
    d. Decision date:7/24/2025
    e. Approved equity ratio: 50.04%
    f. Approved ROE: 10.20%

2. Jurisdiction: Michigan

   a. Docket: U-21488
   b. Client: Alpena Power Company
   c. Subject: ROE
   d. Decision date: 7/23/2024
   e. Approved equity ratio: [not stated in settlement]
   f. Approved ROE: 9.85%

3. Jurisdiction: The Bahamas
   a. Docket: GBPC Rate Case Application 2025-2027[1]
   b. Client: Grand Bahama Power
   c. Subject: ROE
   d. Decision date: [suspended indefinitely]
   e. Approved equity Ratio: N/A
   f. Approved ROE: N/A
   g. Note: the report for this proceeding was not made public.

4. Jurisdiction: Wisconsin
   a. Docket: 5230-GR-108
   b. Client: St. Croix Valley Gas Company
   c. Subject: ROE
   d. Decision date: 7/31/2020
   e. Approved equity Ratio: 60%
   f. Approved ROE: 11.00%

CA Energy Consulting has provided copies of the relevant testimony, reports, and final decisions (please see CAEC_Exh-N_M1-OPG-001_Att-1).

[1] https://gbpa.com/city-services/power-company-regulation/.

Ontario Power Generation Interrogatory #M1-OPG-002

Interrogatory

Reference:

Exhibit M1, p. 41 of 53.

Preamble:

"We note that these metrics are calculated on the basis of OPG's historical and forecasted financial data. To the extent that these forecasts are adjusted at the conclusion of this proceeding, the recommended equity ratio range may require an update, as the recommendation is based, in part, on these forecasted values."

Questions:

a) Please confirm whether "the conclusion of this proceeding" means sometime after a final decision is issued by the OEB.
b) If, based on the OEB's decision in this case, the "forecasts are adjusted" to an extent that it requires an update to the equity ratio range, by what mechanism would any such change be reflected in the record in this proceeding?
c) Please identify which forecasted financial data inputs, if adjusted, would require a revision to CAEC's recommended equity ratio range.

Response:

The following response is provided by CA Energy Consulting.

a) Confirmed.
b) Unless directed by the OEB, CA Energy Consulting will not file supplementary evidence in this proceeding. The statement referenced in this question provides a disclaimer that the credit metrics are based on company filed evidence. If these forecasted data were to be adjusted, the credit metrics would be affected.
c) The preamble to this question refers to the data underlying the credit metrics analysis. Specifically, the text in refers to the forecasted data used to calculate FFO/Debt, CFO/Debt, Debt/EBITDA, and FFO/Interest.

Ontario Power Generation Interrogatory #M1-OPG-003

Interrogatory

Reference:

Exhibit M1, p. 44 of 53, Table 6.4

Questions:

a) For the three Canadian Crown Corporations in CAEC's proxy group:
   i. Provide the credit rating from S&P Global, Moody's, DBRS, and Fitch;
   ii. Provide the most recent credit rating reports from S&P Global, Moody's, DBRS, and Fitch;
   iii. Identify whether the entity has its own stand-alone issuer credit rating;
   iv. Identify whether the entity issues its own long-term debt; and
   v. Identify whether it has a provincial debt guarantee.

b) In preparing its report, did CAEC conduct any analysis of the credit ratings or credit metrics (e.g., FFO/Debt or CFO/Debt ratios) of the three Canadian Crown Corporations that it proposes adding to the proxy group for OPG? If so, please provide that analysis.

Response:

The following response is provided by CA Energy Consulting.

a) NB Power

   i. NB Power does not have its own credit rating as all borrowing is done directly though the Province of New Brunswick.
   ii. Please see answer to part (i).
   iii. Please see answer to part (i).
   iv. Please see answer to part (i).
   v. Please see answer to part (i).

   BC Hydro

i. *S&P Global* – The Province of British Columbia received an A credit rating with a negative outlook.[2] *Moody's* – BC Hydro received an Aa2 credit rating with a negative outlook.[3] *DBRS* – BC Hydro received and AA (high) credit rating with a negative trend from DBRS.[4] *Fitch* – BC Hydro received an AA+ credit rating with a stable outlook in 2024.[5]
ii. Credit rating reports were not obtained as part of the analysis. However, the footnotes to part (i) provide some reports and related information.
iii. Yes, BC Hydro has a standalone credit profile and rating.
iv. Yes, BC Hydro issues long-term debt.
v. BC Hydro's debt is guaranteed by the province.

NL Hydro

i. NL Hydro received an A rating from DBRS.[6] I am not aware of credit ratings for NL Hydro issued by Fitch or Moody's.
ii. Credit rating reports were not obtained as part of the analysis. However, the footnotes to part (i) provide some reports and related information.
iii. My understanding is that the credit rating for NL Hydro is not stand-alone.
iv. NL Hydro issues long term debt.
v. NL Hydro's debt is guaranteed by the province.

b) The screening process for selecting companies in the proxy group contained a set of criteria, including a requirement that companies "have an investment grade credit rating similar to that of OPG" (Exhibit M1, p. 43). This requirement aligns with the criteria used by Concentric in its report (Exhibit C1-1-1, Attachment 1, pp. 62-65). The three Canadian Crown Corporations in the proxy group fulfill this requirement. Further analysis of the credit metrics (e.g., FFO/Debt or CFO/Debt ratios) of the three Canadian Crown Corporations was not conducted.

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[2] https://www.spglobal.com/ratings/en/regulatory/article/-/view/sourceId/101677300.
[3] https://ratings.moodys.com/ratings-news/440567.
[4] https://dbrs.morningstar.com/research/453469/british-columbia-hydro-and-power-authority-credit-rating-report.
[5] https://www.fitchratings.com/research/international-public-finance/fitch-assigns-aa-idr-to-bc-hydro-outlook-stable-19-12-2024.
[6] https://dbrs.morningstar.com/research/459149/morningstar-dbrs-confirms-the-province-of-newfoundland-and-labrador-at-a-and-r-1-low-stable-trends.

Ontario Power Generation Interrogatory #M1-OPG-004

Interrogatory

Reference:

Exhibit M1, p. 44 of 53, Table 6.4

Questions:

a) For each of the Canadian Crown Corporations in CAEC's proxy group, provide the regulatory decision(s) authorizing the "Authorized Equity Ratio" in Table 6.5.
b) For each of the Canadian Crown Corporations considered by CAEC for inclusion in the proxy group (i.e., both those that were included in the proxy group and those that were excluded from the proxy group), provide:
    i. The results on the proxy group screening analysis; and
    ii. The supporting calculations, source documents, and page references for the inputs used to analyze each Canadian Crown Corporation's generation (total, nuclear, and hydroelectric), operating revenues (total and regulated), and net income (total and regulated).

Response:

The following response is provided by CA Energy Consulting.

a) Please see CAEC_Exh-N_M1-OPG-004_Att-1. In responding to this question, we learned that the stated authorized equity ratio for NB Power is 20 percent, rather than 19 percent. However, this does not materially change the findings of the analysis (the proxy group average authorized equity ratio changes from 46.95% to 47.04%).

b) Portions of the requested information has already been provided on May 29th. Please see attached files CAEC_Exh-N_M1-OPG-004_Att-1 for the additional information.

Ontario Power Generation Interrogatory #M1-OPG-005

Interrogatory

Reference:

Exhibit M-1

Questions:

a) Please provide all workpapers and attachments developed and relied on by CAEC to support the recommendations in its report, including for all tables and charts in CAEC's report. Please provide any Excel workpapers in electronic executable format with all formulas intact.
b) To the extent not provided in response to part a), please provide all inputs, formulae, and assumptions used in CAEC's credit metric analyses (Tables 6.2 and 6.3).
c) Please provide all documents cited by CAEC in the footnotes to its report.
d) Please provide copies of any other information or source documents that were developed or relied on by CAEC in support of the tables presented in its report, to the extent not provided in response to parts a) through c).

Response:

The following response is provided by CA Energy Consulting.

a) Please see attached files, also provided on May 29th:
   - CAEC_Exh-N_M1-OPG-005_Att-1_Appendix Figures
   - CAEC_Exh-N_M1-OPG-005_Att-2_Figure 3.1
   - CAEC_Exh-N_M1-OPG-005_Att-3_Figure 3.2
   - CAEC_Exh-N_M1-OPG-005_Att-4_Figure 6.1
   - CAEC_Exh-N_M1-OPG-005_Att-5_Figure 6.2
   - CAEC_Exh-N_M1-OPG-005_Att-6_Table 6.2
   - CAEC_Exh-N_M1-OPG-005_Att-7_Table 6.3
   - CAEC_Exh-N_M1-OPG-005_Att-8_Table 6.4
   - CAEC_Exh-N_M1-OPG-005_Att-9_Table 6.5

b) Please see response to part a).

c) In instances where documents relating to the footnotes in the M1 report are not readily accessible on the OEB's website, these documents are either provided in the hyperlinks or on the pages that follow in several attachments. Please see:
    - CAEC_Exh-N_M1-OPG-005_Att-10_Footnotes_Part 1
    - CAEC_Exh-N_M1-OPG-005_Att-10_Footnotes_Part 2

d) Responses to a) through c) provide the information relied upon.

CCC Interrogatory #M1-CCC-001

Interrogatory

Reference:

Exhibit M1

Questions:

For each proceeding where the author of the Ontario Power Generation Inc. Capital Structure Recommendations Report has provided expert evidence on utility cost of capital, please provide the following information regarding those proceedings, as applicable:

- Jurisdiction
- Date
- Docket Number
- Applicant
- Client
- Existing equity ratio
- Author's recommended equity ratio
- Approved equity ratio as a result of the proceeding, and how it was reached (decision or settlement)
- Existing ROE
- Author's recommended ROE
- Approved ROE as a result of the proceeding, and how it was reached (decision or settlement)
- A copy or web link to the authors written report/testimony
- A copy or web link to the commission/regulatory decision

Response:

The following response is provided by CA Energy Consulting.

Mr. Crowley has provided testimony in the following proceedings. Written reports and testimony, as well as regulatory decisions, can be found in CAEC_Exh-N_M1-OPG-001_Att-1.

1. Jurisdiction: Florida

    a. Decision date:7/24/2025
    b. Docket: 20240099-EI
    c. Applicant: Florida Public Utilities Company
    d. Client: Florida Public Utilities Company
    e. Existing allowed ROE: 10.25%
    f. Existing authorized equity ratio: (not stated: based on actual capital structure)
    g. Approved equity ratio: 50.04% (settlement)
    h. Recommended ROE: 11.30%
    i. Approved ROE: 10.20% (settlement)
    j. No equity ratio recommended.

2. Jurisdiction: Michigan

    a. Decision date: 7/23/2024
    b. Docket: U-21488
    c. Applicant: Alpena Power Company
    d. Client: Alpena Power Company
    e. Existing allowed ROE: 9.85%
    f. Existing authorized equity ratio: (not stated in settlement)
    g. Approved equity ratio: (not stated in settlement)
    h. Recommended ROE: 11.91%
    i. Approved ROE: 9.85% (settlement)
    j. No equity ratio recommended.

3. Jurisdiction: The Bahamas

    a. Decision date: [suspended indefinitely]
    b. Docket: GBPC Rate Case Application 2025-2027[7]
    c. Applicant: Grand Bahama Power
    d. Client: Grand Bahama Power
    e. Existing allowed ROE: (not stated)
    f. Existing authorized equity ratio: (not stated in settlement)
    g. Approved equity ratio: N/A

[7] https://gbpa.com/city-services/power-company-regulation/.

h. Recommended ROE: 12.90%
i. Approved ROE: N/A
j. No equity ratio recommended.
k. Note: the report for this proceeding was not made public.

4. Jurisdiction: Wisconsin

   a. Decision date: 7/31/2020
   b. Docket: 5230-GR-108
   c. Applicant: St. Croix Valley Gas Company
   d. Client: St. Croix Valley Gas Company
   e. Existing allowed ROE: 11.00%
   f. Existing authorized equity ratio: 75%
   g. Approved equity Ratio: 60% (settlement)
   h. Recommended ROE: 11.17%
   i. Approved ROE: 11.00% (settlement)
   j. No equity ratio recommended.

CCC Interrogatory #M1-CCC-002

Interrogatory

Reference:

Exhibit M1, p. 20

Question(s):

a) Please confirm that Christensen applied the OEB-approved 2026 ROE of 9.11% in its analysis of the appropriate capital structure for OPG.
b) Please advise whether Christensen agrees that the deemed equity ratio and authorized must be considered together to determine whether the Fair Return Standard has been met. If not, please explain.
c) To the extent that the OEB-approved 2027 ROE is higher than 9.11%, please explain the implications for Christensen's analysis of the appropriate capital structure for OPG.
d) Please confirm that the DNNP was not reflected in Christensen's analysis of the appropriate capital structure for OPG.

Response:

The following response is provided by CA Energy Consulting.

a) Confirmed.
b) Agreed.
c) Changes in the OEB-approved 2027 ROE would result from changes in either the Long Canada Bond Forecast or the A-rated Utility Corporate Bond spread (see Exhibit M1, p. 13), or a change in both. Changes in either of these parameters would reflect changes in macroeconomic risk levels that affect utility cost of capital. In this way, the ROE formula captures required adjustments to OPG's authorized weighted average cost of capital. This is why changes in the allowed ROE would not necessitate a change to the authorized capital structure.
d) Confirmed.

CCC Interrogatory #M1-CCC-003

Interrogatory

Reference:

Exhibit M1, pp. 22-23

Preamble:

Christensen states "[n]uclear plants have very high fixed costs and are generally "must-run" facilities, which means that utilities with a high proportion of nuclear power cannot easily scale output with demand—particularly if demand falls. This means that generation costs remain high for the utility even as revenue falls."

Question(s):

In the scenario that there is no meaningful risk of nuclear generation curtailment related to demand reductions (i.e., nuclear generation provides baseload supply and always produces electricity for sale to the market when available), please discuss the implications for Christensen's analysis of OPG's business risk related to increased nuclear generating plant.

Response:

The following response is provided by CA Energy Consulting.

A utility that has no risk of nuclear generation curtailment and a pre-defined payment amount set regardless of market prices will have lower business risk than a utility operating in a competitive market for generation services, all else equal. However, other factors related to increasing the proportion of nuclear generation output, such as concentration risk, would likely impose upward pressure on the utility's cost of capital relative to utilities with a more diverse generation mix. We considered these factors, as well as the OEB's finding that nuclear power generation poses a greater risk than hydroelectric power.

As shown in Exhibit M1, Table 7.1, we found the affect of OPG's asset mix on risk, and therefore the cost of capital, to be "ambiguous"—meaning it did not increase or decrease our recommended equity ratio for the current payment amounts period.

CCC Interrogatory #M1-CCC-004

Interrogatory

Reference:

Exhibit M1, pp. 24-25

Preamble:

Christensen states "[w]e agree that weather risks are likely to increase for utilities, generally speaking, over time as climate change worsens. Power generation facilities may need to adapt to demand fluctuations and potentially milder winters, on average, interspersed with more volatile temperature swings. In this way, OPG's weather risks are potentially somewhat greater than during the last payment amounts proceeding."

Question(s):

Please advise whether Christensen's views on weather risk are related to demand and production risk or related to physical damage risk.

Response:

The following response is provided by CA Energy Consulting.

The statement referenced in this question refers to generic risks that utilities face as a result of climate change. Generally, weather risk may result in both demand and production risk and to physical damage risk.

CCC Interrogatory #M1-CCC-005

Interrogatory

Reference:

Exhibit M1, pp. 26-27

Preamble:

Christensen states that "[o]ther potential changes such as the lifting of the hydroelectric rate freeze established in the EB-2020-0290 proceeding also reduce risks somewhat."

Question(s):

Please further explain why the transition from a rate freeze to forward test year rebasing with a custom IR ratemaking framework for hydroelectric cost recovery is described to only reduce risks somewhat.

Response:

The following response is provided by CA Energy Consulting.

During the 2027-2031 payment amounts period, OPG has proposed to set hydroelectric cost recovery according to a customized price cap index. The requested price cap formula contains an X factor of zero and forecasted elements related to the recovery of capital spending, resulting in annual payment amounts adjustments according to inflation and the Company's cost forecasts.

The Company had numerous variance and deferral accounts to reduce risk during the previous payment amount period but had to operate under a frozen payment amount each year. As such, the Company was required to operate under a framework with no revenue recovery for cost growth. Under the proposed 2027-2031 payment amounts plan, OPG will operate under a framework that provides revenue recovery for cost growth approximately equal to OPG's costs.

This is a slight reduction in risk because it allows for payment amounts that match costs during a period of high-cost growth while at the same time considering that OPG already had several variance accounts that reduced hydroelectric risks and company-wide risks associated with changing costs during the 2022-2026 payment amounts period (see Exhibit M1, Table 5.1).

CCC Interrogatory #M1-CCC-006

Interrogatory

Reference:

Exhibit M1, pp. 26-27

Preamble:

Christensen states that "[w]e agree that CCR causes upward impacts to OPG's creditworthiness relative to a framework that includes no means of concurrent cost recovery. However, the CCR mechanism only provides OPG with revenue recovery according to its long-term debt rate. The CCR mechanism does not recover OPG's WACC, as it does not include the cost rate of equity financing. Therefore, CCR, as designated under Ontario Regulation 53/05, likely provides a slight reduction to OPG's financial risk relative to the previous payment amounts period, when no such mechanism existed."

Question(s):

Please further explain the statement that the introduction of CCR provides "a slight reduction to OPG's financial risk..." As part of the response, please consider that the CCR for the PRP is expected to provide OPG with about $2.9 billion of revenues over the 2027-2031[8] period that, in the absence of CCR, it would have no access to. In addition, please further discuss Christensen's apparent concern with the provision of CWIP financing at OPG's long-term debt rate as opposed to the WACC.

Response:

The following response is provided by CA Energy Consulting.

Concurrent cost recovery (CCR) affects *when* OPG will recover revenue for financing costs, but, if calculated correctly, would not change the ultimate amount of revenue recovery. As such, CCR reduces liquidity risks during the payment period but should not substantially affect OPG's long-term financial risk. This is why CCR provides a slight reduction, rather than a major reduction, in financial risk.

[8] Exhibit I1, Tab 1, Schedule 1, Table 2 (Line 22a).

A CCR mechanism that employs a utility's weighted average cost of capital (WACC) will correctly account for the concurrent cost of capital financing, as the utility incurs the WACC during the period between rate cases. As OPG's capital structure includes equity, the Company's long term debt rate does not fully capture the Company's WACC. A CCR mechanism based on the Company's WACC would reduce risk more than a CCR mechanism based solely on the cost of long-term debt.

CCC Interrogatory #M1-CCC-007

Interrogatory

Reference:

Exhibit M1, pp. 40-42

Preamble:

Concentric states in footnote 150 that “[f]or the FFO/Debt and CFO/Debt ratios, we calculated Total Debt using the same method as Concentric, which is based on the Moody’s and S&P methods, respectively.”

Question(s):

a) Please confirm that Christensen applied the same inputs (e.g. EBITDA, total debt, etc.) for the credit metric analysis as was applied by Concentric in its “Credit Metric Analysis Working Paper” for its analysis set out in Table 6.3. If not, please explain.
b) Please advise whether the FFO/Debt and CFO/Debt ratio calculations are the same as Moody’s and S&P in terms of only the formula or the formula as well as the inputs (e.g. EBITDA, total debt, etc.) to the formula. To the extent that it is only the formula that is the same, please explain the differences in terms of the inputs that were used by Christensen and those that are used by Moody’s and S&P.
c) Please provide the live excel spreadsheet that supports the historical credit metrics shown in Table 6.2.
d) Please provide the live excel spreadsheet that supports the forecast credit metrics in different scenarios shown in Table 6.3.

Response:

The following response is provided by CA Energy Consulting.

a) This is confirmed for the calculation of FFO/Debt and CFO/Debt. However the calculation of Debt/EBITDA and FFO/Interest Expense used other inputs.
b) Both inputs and the formula were the same.

c) Please see CAEC_Exh-N_M1-OPG-005_Att-6_Table 6.2, also provided on May 29th.
d) Please see CAEC_Exh-N_M1-OPG-005_Att-7_Table 6.3, also provided on May 29th.

CCC Interrogatory #M1-CCC-008

Interrogatory

Reference:

Exhibit M1, pp. 43-48
BCUC, Decision and Order (G-154-23), June 19, 2023, p. 3

Question(s):

a) Please provide an excel spreadsheet, in a format that is similar to L1-CCC-030, Attachment 1, the proxy group screening that was performed by Christensen. As part of the response, please show the screening applied to all the companies that form part of Christensen's peer group and the companies that were included in Concentric's peer group. Also, please specifically, discuss the rationale for the exclusion of Maritime Electric, Newfoundland Power and Nova Scotia Power (assuming they were excluded from the peer group).
b) Please provide Christensen's view, and provide the results of its screening methodology, with respect to the potential inclusion of Manitoba Hydro and SaskPower.
c) Please provide an excel spreadsheet, in a format that is similar to L1-CCC-031, Attachment 1, showing the calculation of the mean and median authorized equity ratios. As part of this response, please also discuss whether Christensen is calculating the authorized equity ratios at the operating subsidiary or Holdco level and explain why it elected to use the approach that it selected.
d) With respect to the average authorized equity ratio for British Columbia Hydro and Power Authority, the BCUC Decision and Order (G-154-23) appears to reference a definition, established in "Direction No. 8 to the BCUC" (see Footnote 10), that deemed equity is to be set at 30%. Please advise whether the British Columbia Hydro and Power Authority equity thickness should be 30% or 40% (as is currently shown in Table 6.5)

Response:

The following response is provided by CA Energy Consulting.

a) Please see file CAEC_Exh-N_M1-OPG-005_Att-8_Table 6.4, also provided on May 29th. Nova Scotia Power is owned by Emera. As shown in the file Table

6.4.xlsx, Emera did not pass the screen as it does not own sufficient nuclear and hydroelectric generation assets. Maritime Electric is owned by Fortis. As shown in the file Table 6.4.xlsx, Maritime Electric did not pass the screen as it does not own sufficient nuclear and hydroelectric generation assets. Newfoundland Power does not own substantial generation assets, and was therefore not considered.

b) Please see CAEC_Exh-N_M1-OPG-005_Att-8_Table 6.4, also provided on May 29th for the corresponding workpapers. As shown in these workpapers, SaskPower did not own sufficient nuclear and/or hydroelectric generation to pass the screen. Manitoba Hydro did not have a sufficient proportion of electric revenue relative to total revenue nor a sufficient proportion of electric income relative to total income, as Manitoba is also a distributor of natural gas.

c) Please see file CAEC_Exh-N_M1-OPG-005_Att-9_Table 6.5, also provided on May 29th. The authorized equity ratios reflect the simple average of the authorized equity ratios for the operating subsidiaries of each holding company. This approach was selected because it captures the capital structures of each operating company, which often operate in different jurisdictions and with different regulators.

d) BC Hydro is authorized to reach an equity ratio of 40 percent. In 2014, a policy decision was made and outlined in Order in Council No. 095/2014 (please see attached CAEC_Exh-N_M1-CCC-008_Att-1_Order), which states that BC Hydro will not pay the province of British Columbia a dividend until BC Hydro achieves a 60:40 debt to equity ratio. This policy decision remains in effect (please see attached CAEC_Exh-N_M1-CCC-008_Att-2_BC Hydro_Report).

   However, BC Hydro currently uses a “deemed” equity ratio of 30%. This is the value that is currently used in calculating BC Hydro’s allowed return (see BCUC Decision and Order G-154-23, June 19, 2023, p. 3, as per attached CAEC_Exh-N_M1-CCC-008_Att-3_Decision).

   An authorized equity ratio is the equity ratio that a regulator would allow a company to use to calculate its weighted average cost of capital. A deemed equity ratio is the actual equity ratio used in the calculation of a company’s weighted average cost of capital. Typically, these values are the same. In this case, the authorized equity ratio and the deemed equity ratio differ.

BC Hydro is a unique utility in that the portion of the company's revenue requirement attributable to total return is established not by a cost of equity analysis, but rather by a required "distributable surplus" that the utility provides to the province of British Columbia. As stated in Order G-154-23, June 19, 2023 (see attached CAEC_Exh-N_M1-CCC-008_Att-3_Decision):

> "In regulating and setting rates for the authority for F2020, F2021, F2022, F2023, F2024 and F2025, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million." (p. 3)

In other words, the total allowed return is set such that BC Hydro's distributable surplus equals a certain dollar value in expectation. The deemed capital structure is calibrated accordingly.

Although the current deemed capital structure is currently 70:30 (see CAEC_Exh-N_M1-CCC-008_Att-4_Direction), BC Hydro is authorized to set its equity ratio as high as 40%, after which the company would pay dividends to the province.

WTFN Interrogatory #M2-WTFN-001

Interrogatory

Reference:

Exhibit M2, Research Report on Financing New Utility Investments; A2-Staff-016.

Electrification and Energy Transition Panel (EETP), Ontario's Clean Energy Opportunity, s.4.3.

Preamble:

OPG states in response to A2-Staff-016 that it is working with WTFN to explore economic opportunities, including potential equity participation in DNNP. Attachment 1 to A2-Staff-016 provides a copy of the letter from the Ministry of Energy and Mines that asks OPG to prioritize economic reconciliation opportunities on OPG's major projects.

The EETP Report states that to enable Indigenous participation and achieve true partnerships, it is important to understand the economics of Indigenous governments and how they differ from other forms of government in Canada.

Questions:

a) Section 2.2 of the research report provides a summary of the proposed financing for DNNP LP. Did the research report consider equity investments by First Nations partners in DNNP LP?
b) Do any of the financing examples of nuclear projects included in Table 1 include equity investment by First Nations partners?
c) Does Christensen Associates agree that equity investment by a First Nations partner in a single-asset generator, such as DNNP LP, is significantly risker than investment in a diversified generator with many different asset types, like OPG? If not, please explain why.
d) How do the conclusions of the research report prioritize economic reconciliation opportunities for First Nations partners?
e) Please describe what consultation activities Christensen Associates undertook with First Nations in preparing the research report.

f) How did Christensen Associates seek to understand the economics of Indigenous governments, such as a potential equity investment by WTFN in DNNP LP, and how they differ from other forms of government in Canada.

<u>Response:</u>

The following response is provided by CA Energy Consulting.

Exhibit M2, Research Report on Financing New Utility Investments, was an undertaking conducted for the purpose of providing additional context to the Polar Star Advisory report (see Staff Evidence Attachment 3 Scope of Work) filed as evidence in this proceeding. As stated in the March 5, 2026 Scope of Work[9] for this research:

> "The Vendor is not being asked to provide an opinion on the proposed equity structure for DNNP LP or on any of the matters on which Polar Star opined; rather, the purpose is to provide purely factual information about historical bond offerings, with a view to providing some factual context for this aspect of the application."

The Scope of Work did not include provisions for additional research related to First Nations financing, economic reconciliation, or consultation. Given this context, we answer the questions below.

a) Section 2.2 of Exhibit M2 provides, as background, financing information related to DNNP, LP. The evidence on the record does not indicate that financing for DNNP, LP was obtained directly from First Nations.
b) The research did not consider whether nuclear generation financing was provided by First Nations partners, as this was not considered in the Polar Star Advisory report.
c) The research report did not provide an expert opinion on the risk level of DNNP, LP relative to other generating companies.
d) CA Energy Consulting was not asked to research economic reconciliation opportunities as part of the work undertaken to produce this report.
e) CA Energy Consulting was not asked to undertake consultation activities with First Nations as part of the work undertaken to produce this report.
f) CA Energy Consulting was not asked to research the economics of Indigenous governments as part of the work undertaken to produce this report.

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[9] Staff_Evidence_Att_3_Scope of Work, May 26, 2026.

Ontario Power Generation Interrogatory #M3-OPG-006

Interrogatory

Questions:

a) Did OEB Staff ask CAEC to develop an alternative econometric model in place of ScottMadden's model for determining Darlington's normalized TGC/MWh and resulting stretch factor?

   i. Please provide a copy of the specific instructions received from OEB Staff and explain how CAEC responded to these instructions.

b) Did CAEC develop an alternative econometric model that it recommends the OEB use in place of ScottMadden's model for determining Darlington's normalized TGC/MWh and resulting stretch factor.

   i. If yes, please provide the model specification, coefficients, standard errors, workpapers, and resulting Darlington placement, and explain why this was not disclosed in the report that was filed on May 26.

Response:

a) No. Please see CAEC_Exh_N.M3-OPG-006_Att-1_Statement of Work. CAEC was asked to prepare a written report that included a "critique of the ScottMadden report, including the econometric methods, analysis, and data underpinning the report." CAEC performed this task as requested by OEB staff.

   OEB staff has also responded to this specific interrogatory in the Cover Letter that accompanies the responses to these interrogatories.

b) No.

Ontario Power Generation Interrogatory #M3-OPG-007

Interrogatory

Preamble:

CAEC states that ScottMadden's CANDU coefficient captures factors unique to Bruce or Pickering and likely accounts for controllable cost-driving factors at Darlington.

Questions:

a) In CAEC's opinion, what specific controllable factors at DNGS is the CANDU variable accounting for? Please provide any analysis (including calculations and assumptions) that supports this opinion.
b) Is CAEC essentially claiming that the refurbishment at Bruce increased the CANDU coefficient and also that Pickering having not yet done a refurbishment has also increased the CANDU coefficient?
c) Does CAEC agree that CANDU technology materially impacts TGC/MWh?
    a. If no, explain why and provide the supporting analysis that CAEC relies on.
    b. If yes, please confirm that any proper benchmarking analysis would necessarily be highly sensitive to the costs attributed to the CANDU technology.

d) Please confirm whether CAEC has verified that Bruce life-extension, Refurbishment, or Major Component Replacement costs were included in the EUCG TGC data used in ScottMadden's econometric model.

e) Please quantify, to the extent possible, the portion of the $539 million CANDU coefficient that CAEC attributes to:
   i) Bruce Life-Extension Program, Major Component Replacement, or other Bruce-specific costs;
   ii) Pickering age, refurbishment status, or other Pickering-specific costs;
   iii) Controllable cost-performance differences among CANDU plants; and
   iv) Other factors not related to CANDU technology.

   If CAEC cannot quantify items i) to iv) above, explain why.

f) If CAEC is unable to quantify any of the amounts requested in response to d and e, please explain the evidentiary basis for concluding that the CANDU coefficient is overstated by enough to move Darlington from the third quintile to the fourth quintile.

<u>Response:</u>

a) CAEC does not have an opinion about the specific controllable factors that the CANDU variable is accounting for. CAEC is simply noting that there is likely a difference in controllable factors between CANDU and non-CANDU plants on average, and the effect of that difference on TGC will be absorbed by the technology coefficients in ScottMadden's econometric model.
b) CAEC is claiming that if Bruce experiences an increase in costs that is not experienced by other plants in the data, then this will increase the CANDU coefficient. Because these costs are not experienced by Pickering and Darlington, they are unrelated to the CANDU technology and should not be accounted for in the CANDU coefficient. It is CAEC's understanding that this is due to the Life Extension Program at Bruce, as supported in the figure below. CAEC is also claiming that age is likely incorrectly specified in the model, and so higher TGC at Pickering may not be explained by the Average Unit Age variable and will instead be absorbed by the CANDU coefficient.
c) As demonstrated in CAEC's report, the CANDU coefficient as estimated by ScottMadden is not accurate. Furthermore, CAEC's report did not specify an alternative econometric analysis. Therefore, CAEC does not have an opinion about the extent to which the CANDU technology impacts TGC/MWh.
d) CAEC only has access to the materials provided by ScottMadden, which support the claim that costs caused by the Bruce refurbishment program are included in the EUCG TGC data. [redacted]

[redacted]

e) An alternative econometric model is required to quantify the individual components of the coefficient. This was outside of the scope of CAEC's report as shown in CAEC_Exh_N.M3-OPG-006_Att-1_Statement of Work.

CAEC has shown that if the inflation-adjusted CANDU coefficient of $343 million from ScottMadden's 2020 report was adopted, the stretch factor would be 0.6%. ScottMadden has not been able to explain the steep increase in the coefficient to $539 million, instead noting that the coefficient is capturing any "persistent CANDU-site characteristics that are not separately controlled for and that are common to those Canadian stations."[10] Persistent characteristics would by definition not cause a change in the coefficient. CAEC has offered evidence that at least a portion of this change from $343 million to $539 million could be explained by, for instance, the refurbishment costs at Bruce. Because even a small change in the coefficient from $539 million to $523 million would imply a 0.45% stretch factor, this recommendation is arguably conservative.

[10] Ontario Energy Board. *EB-2025-0297. Exhibit L-F2-Staff-324, Page 4.* April 22, 2026.

Ontario Power Generation Interrogatory # M3-OPG-008

Interrogatory

Preamble:

CAEC states that "a corrected coefficient lower than $523 million is reasonable."

Questions:

a) Is $523 million CAEC's estimate of a corrected CANDU coefficient?
    i. If yes, please provide the supporting calculations and assumptions for this correction.
    ii. If no, please confirm that $523 million is the numerical threshold at which Darlington's stretch factor classification changes from 0.3% to 0.45%. If not confirmed, please explain the basis for the $523 million threshold.

Please provide the workpapers supporting Figures 2.1 and 2.2, including the calculation of Darlington's normalized TGC/MWh and quintile placement at the $523 million and $426 million CANDU coefficient levels.

Response:

No. CAEC confirms that $523 million is the numerical threshold at which Darlington's stretch factor classification changes from 0.3% to 0.45%. Please see CAEC_Exh_N.M3-OPG-008_Att-1_CAEC_Figures.

Ontario Power Generation Interrogatory #M3-OPG-009

Interrogatory

Preamble:

CAEC states that the Average Unit Age effect may not be economically meaningful as constructed because plant age is not reduced following refurbishment.

Questions:

a) Did CAEC test an alternative age variable that resets or otherwise adjusts for refurbishment.
   i. If yes, please provide the results and supporting calculations and assumptions.
   ii. If no, please provide the analysis (and supporting calculations and assumptions) which supports the referenced observation.

Response:

No. The observation was based on the construction of the Average Unit Age variable, which is defined in the “IAEA Unit Data and Weighting” sheet within “Master Data Adjusted For 0 Generation – ORIGINAL.xlsx”

Ontario Power Generation Interrogatory #M3-OPG-010

Interrogatory

Preamble:

CAEC states that the planned outage adjustment may overstate the performance of plants with high planned outage rates, but also states that the adjustment does not have a material impact on CAEC's recommended stretch factor.

Questions:

a) Please confirm whether CAEC relies on its planned outage critique as a basis for recommending a higher stretch factor. If so, please provide Darlington's TGC/MWh, quintile placement, and indicated stretch factor with and without the planned outage adjustment.
b) Please confirm that CANDU plants have a higher minimum, higher median, and higher maximum of planned outages than the other two plant types.
c) CAEC mentions the possibility that the variation in planned outages may be controllable, however, is it also possible that there are other uncontrollable factors at the other plants causing the variation?
    i. If yes, has CAEC investigated these possible uncontrollable factors? If so, please provide the results and details on the analysis.

Response:

a) Not confirmed. The planned outage adjustment was made to the data in CAEC's Figures 2.1 and 2.2. Darlington's TGC/MWh, quintile placement, and indicated stretch factor with and without the planned outage adjustment can be found in ScottMadden's report.
b) Confirmed.
c) It is possible that other uncontrollable factors cause this variation. CAEC has not investigated these possible uncontrollable factors.

Ontario Power Generation Interrogatory #M3-OPG-011

Interrogatory

Question:

Please provide Darlington's normalized TGC/MWh percentile/quintile placement and indicated stretch factor under i) CAEC's preferred CANDU coefficient, if any; and ii) any other scenario CAEC relies on to support its recommendation that the stretch factor be increased from 0.3% to 0.45%.

Response:

Please see response to M3-OPG-001, part f.

Ontario Power Generation Interrogatory #M3-OPG-012

Interrogatory

Preamble:

CAEC recommends either: (a) broadening the revenue base to include DRP, PRP, and DNNP in-service additions, or (b) adding 15 basis points to the stretch factor to compensate for the narrower base.

Questions:

a) Please describe how OPG can increase cost efficiency on specific assets that have already been placed in the rate base?
b) Will the large increase in the rate base due to these capital projects tend to increase or decrease the proportion of controllable costs to total costs for OPG?
c) Please confirm that capital productivity gains are only possible by lowering future in-service additions and once assets enter the rate base they become fixed costs and are no longer sources of possible capital productivity gains. If CAEC disagrees, please explain
d) Please provide the analysis undertaken by CAEC (and supporting calculations and assumptions) to determine that 15 basis points is an achievable level of incremental productivity.
e) If the projected level of incremental productivity cannot be achieved, what are the potential impacts with respect to the company's ability to:
    i. Carry out prudent and necessary work at its nuclear facilities
    ii. Earn the regulated deemed rate of return

Response:

a) Please see our answer to part c). In addition, the application of a stretch factor is better understood as an aggregate efficiency expectation rather than a uniform line-by-line cost efficiency achievement for each asset or cost category. This interpretation is consistent with the OEB precedent described in Section 3.2.2 of the report, which explains that, for distribution utilities regulated by the OEB, the stretch factor is applied to the entire base revenue requirement, not to discrete components in isolation.
b) The effect depends on how "proportion of controllable costs" is defined. There are at least two distinct issues. First, there is the accounting classification question: what dollar categories are labeled controllable versus non-controllable? Second, what degree of control does the utility have over each cost category? While depreciation, return, and taxes due to these capital projects can be classified as "less controllable", these capital additions may also affect the extent

to which the utility can control their expenses in some other cost categories. Therefore, the directional effect cannot be determined as a general matter.

c) Not confirmed. While it is true that once assets enter the rate base the utility cannot “rebuild” the same asset cheaper, it doesn’t mean there is no possibility for capital productivity gains. Capital productivity measures the amount of output produced per unit of capital input. An increase in output with no change in capital input will increase capital productivity.

d) Please see Table 3.6 in the report and our reply to M3-CCC-2 a). As stated in section 3.2.4 of our report (p19), the recommendation rests on a stated premise and a condition—"Since OPG uses the same range of stretch factors in the RRF as distribution utilities, if the OEB believes OPG has similar efficiency opportunities as distribution utilities operating under Custom IR”. Under the RRF, the stretch factor is not calculated on a measure-by-measure basis or allocated to any specific identified cost-saving measure.

e) Under incentive regulation, utilities could both over and under earn compared to their regulated deemed rate of return. If the utility fails to manage costs efficiently, the projected level of incremental productivity may not be achieved, and the utility may not earn the regulated deemed rate of return. If OPG contends that the stretch factor adjustment would impair specific prudent and necessary nuclear work and deny it a fair opportunity to earn the regulated deemed rate of return, it should provide specific supporting evidence. Absent that evidence, we could not assess the impacts.

Ontario Power Generation Interrogatory # M3-OPG-013

Interrogatory

Question:

Does CAEC consider that OPG faces analogous business conditions in the 2027-2031 rate period as it did in the 2022-2026 period?

Response:

The question of whether OPG faces analogous business conditions falls outside the scope of this report and has therefore not been examined.

Ontario Power Generation Interrogatory M3-OPG-014

Interrogatory

Questions:

a) Please confirm that, from a statistical standpoint, the expected efficiency gains for an average-performing utility, is equal to the expected efficiency gains of the average-performing utility within the industry.
b) Please confirm that a stretch factor is a term that adds an additional amount of efficiency gains above and beyond what is statistically expected.
c) Has CAEC conducted an analysis of the expected efficiency gains of the nuclear industry? If yes, please provide the results and working papers of the analysis.

Response:

a) Confirmed.
b) Not confirmed. OPG's proposed framework uses a forecasted approach, as noted in our report in Section 3.2.1 (p.14), "[i]n a forecasted rate plan, it is unclear whether the utility's forecast already embeds productivity trends observed across the industry (unlike in a standard indexed cap approach which clearly defines both industry productivity in the productivity factor and company-specific deviation from the industry average in a stretch factor)."
c) No, CAEC has not conducted such analysis.

Ontario Power Generation Interrogatory # M3-OPG-015

Interrogatory

Questions:

a) Please confirm that all cited stretch factor examples in other jurisdictions are significantly below CAEC's recommended stretch factor in this case.
b) Please confirm that there are no nuclear-only stretch factor examples from other jurisdictions that CAEC is aware of. If not able to confirm, please provide examples.
c) Please confirm that there are no generation-only stretch factor examples from other jurisdictions that CA is aware of. If not able to confirm, please provide examples.
d) Please list the utilities in Table 3.5 who have the stretch factor applied only to a subset of revenue.
e) For those utilities listed in part d, please provide the percentage of revenues that the stretch factor is applied to.

Response:

a) Not confirmed. For example, as explained in Appendix A, for Hawaiian Electric Companies, the stretch factor has two components: a 0.22% annual compounding factor and an additional $6.61 million per year "Savings Commitment" (approximately 0.25% of the sum of initial revenue requirements)[11], which sums to approximately 0.47% of the total initial revenue requirement.
b) Confirmed.
c) Confirmed.
d) Table 3.5 in our report does not explicitly categorize utilities based on whether the stretch factor is applied to all revenues or only a subset of revenues. However, based on our review of the underlying materials used to develop Table 3.5, most utilities apply the stretch factor to base revenue requirements (excluding certain passthrough costs and costs associated with exogenous events). Our analysis indicates that the following utilities apply the stretch factor to only a subset of revenues: Fortis BC Inc., FortisBC Energy Inc., and National Grid (Massachusetts).

[11] Calculated by dividing $6.61 million by the sum of initial revenue requirements for all three Hawaiian utilities. The going in revenue requirement for Maui Electric Company was $338.897 million, for Hawai'i Electric Light Company was $394.507 million and for Hawaiian Electric Company was $1,882.846 million. Sources: Hawaii Public Utilities Commission, Docket 2018-0088 Decision and Order 37507 and Order 37557, Docket 2018-0368 Decision and Order 37237, Docket 2017-0150 Decision and Order 36219, and Docket 2019-0085 Decision and Order 37387.

e) Our report and analysis do not quantify the percentage of revenues to which the stretch factor is applied to for each utility. Additionally, the underlying regulatory materials do not explicitly provide these percentages. Based on our additional review of the underlying materials we estimate that, for the utilities to which the stretch factor was only applied to a subset of revenues, approximately 16% of FortisBC Inc.'s[12], 23% of FortisBC Energy Inc.'s[13], and 52% of National Grid's[14] revenues are subject to a stretch factor.

[12] Calculated as the share of formula O&M expenses in the 2025 total revenue requirement, based on the annual review application. The final decision lacks sufficient detail to calculate this share. Source: FortisBC Inc. Annual Review for 2025 and 2026 Rates. July 31, 2025. p. 54 and 77.

[13] A conservative estimate (as taxes and depreciation are not included) calculated as one-half of formula growth capital expenditures (reflecting the assumption that capital spending occurs throughout the year rather than entirely at the beginning), multiplied by the weighted average rate of return, and then added to formula O&M expenses and divided by the total revenue requirement for 2025, based on the annual review application. The final decision does not provide sufficient detail to calculate this share. Source: FortisBC Inc. Annual Review for 2025 and 2026 Rates. July 31, 2025. p. 48, 65, 84 and 132.

[14] Calculated as the share of total O&M expenses in the total cost of service for first year of the rate plan. Source: Massachusetts Department of Public Utilities. D.P.U. 23-150. Order. September 30, 2024. p. 643.

Ontario Power Generation Interrogatory # M3-OPG-016

Interrogatory

Questions:

a) Has CAEC investigated if the controllable costs of OPG's nuclear operations are similar to those of Ontario's distribution utilities? If yes, please provide the results and full details of the analysis.
b) Is CAEC of the opinion that the nuclear industry has "similar efficiency opportunities" as the distribution industry?
c) In CAEC's expert view, are the asymmetric stretch factors in the RRF ranging from 0.0% to 0.6% reasonable additional productivity targets for the distribution industry now that the industry has been under incentive regulation since 2001?

Response:

a) CAEC has not investigated whether controllable costs of OPG's nuclear operations are similar to those of Ontario's distribution utilities.
b) CAEC has not formed an opinion on whether nuclear industry has "similar efficiency opportunities" as the distribution industry for purposes of this proceeding. CAEC's opinion is limited to the recommendation stated in the report.
c) CAEC has not formed an expert view on whether the range of stretch factor is reasonable for purposes of this proceeding. To the extent our report applies the current stretch factor range in the RRF, it does so because it was used by the applicant and it was part of the existing regulatory framework. We did not evaluate whether the range remains appropriate as a policy matter.

CCC Interrogatory #M3-CCC-001

Interrogatory

Reference:

Exhibit M3, pp. 4-7

Exhibit F2-CCC-071, p. 3

Preamble:

In response to F2-CCC-071(b), ScottMadden stated that "[u]sing the same starting point as the prior study (i.e., 2009) and extending the dataset through 2023 does change the outcome of ScottMadden's analysis."

The differences in model coefficients between a 2006 and 2009 starting point for the data set are set out in the table below.

Regression Term / Model Coefficient	Current Study 2009-2023 (2023$Ck)	Current Study 2006-2023 (2023$Ck)
Age	-106	77
Capacity	288	291
CANDU (to BWR Baseline)	555,768	539,467
PWR (to BWR Baseline)	9,595	17,309

Questions:

Please provide Christensen's views on what appear to be very significant changes to model coefficients resulting from the change in the starting point of the data set (as between 2006 and 2009). For example, the age coefficient using 2009 as the starting point is negative while it is positive when using 2006 as the starting point.

Response:

This observation is consistent with imprecise estimation of the model's coefficients. As explained in Section 2.2.1 of CAEC's report, the standard error on the age coefficient is large relative to the size of the coefficient, implying a wide confidence interval. This means the estimator is unstable: repeated sampling will produce significant variation in the coefficient estimate.

CCC Interrogatory #M3-CCC-002

Interrogatory

Reference:

Exhibit M3, p. 22

Questions:

a) Please provide, in an excel spreadsheet, the stretch factor calculation shown in Table 3.6 (which is for 2028 only) for each year of the 2028-2031 period.
b) Please confirm that the "recommended stretch factor adjustment" in Table 3.6 includes the addition of only the capital-related revenue requirement associated with DRP-related assets to OPG's proposal (i.e., does not include Pickering Refurbishment and DNNP capital-related revenue requirement).
c) Please confirm that the result of applying a 0.45% stretch factor to OPG's capital related-revenue requirement inclusive of the DRP-related capital in 2028 would be equivalent to applying the 0.72% stretch factor to OPG's proposed narrower definition for revenue requirement that attracts stretch factor treatment.
d) Please provide Christensen's view on the appropriateness of the application of a stretch factor to the Pickering Refurbishment capital-related revenue requirement.

Response:

a) The excel spreadsheet is provided in CAEC_Exh_N.M3-CCC-002_Att-1_Illustrative stretch factor 2028-2031.
b) Confirmed.
c) Confirmed. In the calculation shown in Table 3.6, the 0.45% stretch factor is applied to revenue requirement OPG proposed to include in stretch amount calculation plus DRP-related capital in 2028.
d) Our analysis focused on the in-service addition of capital investments to the units that were refurbished under that DRP because it was completed before the start of the 2027-2031 rate term and it is the major revenue requirement exclusion from stretch factor application during the 2027-2031 rate term. In principle, the in-service addition related the Pickering Refurbishment program also becomes part of the "used and useful" rate base. We recognize that the Board may have precedent distinguishing between ongoing projects and completed projects for purposes of

stretch factor application during the rate term. To the extent that precedent applies to Pickering Refurbishment capital-related revenue requirement, we would not object to it being treated consistently with that precedent for this rate term. The quantitative effect of its inclusion or exclusion during this rate term is relatively small.

WTFN Interrogatory # M3-WTFN-002

Interrogatory

Reference:

Exhibit M3

Preamble:

In section 4 of the report titled "Conclusions", Christensen Associates states that a reduced effective stretch factor weakens the link between OPG's cost performance and its revenue requirement, disincentivizing the utility to improve cost efficiency. Christensen Associates attributes a portion of this potential cost inefficiency to the exclusion of $2,385 million of the 2028-2031 revenue from DNNP. To correct for this, Christensen Associates proposes two approaches to the OEB: (1) that in-service additions for the large capital program be included in the "stretch amount" calculation; or (2) increase the stretch factor from 0.3 to 0.45.

In section 2.1 of the report, Christensen Associates states that the goal of a cost benchmarking study for the purpose of setting a stretch factor is to uncover the regulated company's expected cost efficiency gains during the rate term. An appropriate cost benchmarking methodology recovers the company's cost performance using data on its costs, outputs, and exogenous operating conditions. Differences in unit costs (e.g. TGC/MWh) can reflect differences in cost efficiency levels if the proper adjustments are made to unit costs. A plant is more cost efficient than a peer if it faces identical operating conditions, which are outside of its control, and is able to produce the same or higher output by using fewer inputs.

In section 3.2.3 and 3.2.4, Christensen Associates assumes that OPG has similar efficiency opportunities as distribution utilities operating under Custom IR.

Questions:

a) In the scenario where in-service additions for DNNP are included in the stretch factor calculation:

    i) Please explain the methodology and analysis Christensen Associates conducted to support its conclusion that a stretch factor of 0.3 is appropriate for DNNP.

    ii) Please provide a list of the peers used in the analysis in (a)(i) to benchmark DNNP.

iii) Please describe what unit and/or total costs were benchmarked between DNNP and the peers listed in (a)(ii). Please provide any comparative cost analysis.

iv) How did Christensen Associates ascertain the expected sector productivity trend for DNNP in the response to (a)(i)?

v) Please provide the analysis, spreadsheets, notes, workbooks and all other relevant records for the responses to (a)(i) through (a)(iv) above.

b) In the scenario where the stretch factor is increased from 0.3 to 0.45:

i) What proportion of the 0.15 increase is attributed to the exclusion of DNNP revenue requirement from adjustment by the stretch factor?

ii) Please explain the methodology and analysis Christensen Associates conducted to support its conclusion that an increase in stretch factor of 0.15 is appropriate. In particular, please describe and break out how DNNP factored into this analysis.

iii) Please provide a list of the peers used in the benchmarking analysis in above in response to (b)(i) or (b)(ii).

iv) Please provide the analysis, spreadsheets, notes, workbooks and all other relevant records for the responses to (b)(i) through (b)(iii) above.

c) Please describe in detail what methodology, analysis or rationale was used to support the assumption that electricity distribution utilities are comparable to DNNP for the purposes of establishing a stretch factor.

i) In response to this question, please explain how sector productivity trends for electricity distributors are relevant benchmarks and can be relied upon to establish a stretch factor for DNNP, which is a first of its kind nuclear generation facility.

<u>Response:</u>

a)

i) Our discussion of DNNP in Sections 3.1 and 3.2 was part of a broader observation that OPG's proposal excludes significant portions of revenue requirement from the application of the stretch factor, thereby reducing the effective stretch factor relative to Ontario distribution utilities under Custom IR. In that context, DNNP was discussed as one of several excluded revenue components. In the last application, OPG used a production-weighted average approach to determine a combined stretch factor value for all operating nuclear fleets. If we use a similar approach using the production forecast provided by the OPG, whether the specific stretch factor for DNNP is 0% or 0.6%, it does not affect our recommended stretch factor for this rate term. Illustrative calculations based on OPG's proposal are shown below.

	Value	
Input	**Assumption 1**	**Assumption 2**
Average Forecasted 2027-2031 Darlington production (TWh)[15]	24.88	24.88
Average Forecasted 2027-2031 Pickering production (TWh)[16]	0.38	0.38
Average Forecasted 2027-2031 DNNP production (TWh)[17]	0.48	0.48
Darlington stretch factor (OPG proposal)[18]	0.30%	0.30%
Pickering stretch factor (based on ScottMadden's benchmarking analysis)[19]	0.30%	0.30%
DNNP stretch factor (assumption)	**0.00%**	**0.60%**
Production-weighted average stretch factor	0.29%	0.31%
Rounded to Closest RRF stretch factor	0.30%	0.30%

ii) Christensen Associates did not identify or use any peers to benchmark DNNP, because it did not perform a DNNP-specific benchmarking analysis.
iii) Christensen Associates did not benchmark any unit or total costs for DNNP and did not perform a comparative cost analysis for DNNP.
iv) Christensen Associates did not estimate an expected sector productivity trend for DNNP.
v) Christensen Associates has no DNNP-specific analysis, spreadsheets, notes, workbooks, or other records responsive to parts (i) through (iv), because no DNNP-specific benchmarking analysis was undertaken.

b)
i) Our recommendation of the additional 0.15 increase is based on the calculation in Table 3.6 of the report, which does not include any DNNP revenue requirement. So the increase is not attributed to the exclusion of DNNP revenue requirement from adjustment by the stretch factor.

[15] Ontario Energy Board. EB-2025-0297. Exhibit E2, Tab 1, Schedule 1, Table 1, Line No. 1, column (h)-(l).
[16] Ontario Energy Board. EB-2025-0297. Exhibit E2, Tab 1, Schedule 1, Table 1, Line No. 2, column (h)-(l).
[17] Ontario Energy Board. EB-2025-0297. Exhibit E2, Tab 1, Schedule 1, Table 1, Line No. 4, column (h)-(l).
[18] Ontario Energy Board. EB-2025-0297. Exhibit A1, Table 3, Schedule 2, page 32.
[19] Ontario Energy Board. EB-2025-0297. Exhibit F2, Tab 1, Schedule 1, page 13. Pickering places at 28th out of the 57 sites (the third quintile).

ii) Please see our answer to part i)

iii) As the increase is not attributed to the exclusion of DNNP revenue requirement, there is no additional benchmarking analysis conducted.

iv) Please see our response to M3-CCC-2 a) for the excel spreadsheet used to calculate recommended stretch factor adjustments.

c)

i) CAEC did not assume electricity distribution utilities are comparable to DNNP for the purpose of establishing a stretch factor. To the extent our report applies the current stretch factor range in the RRF, it does so because it was used by the applicant and it was part of the existing regulatory framework. As stated in section 3.2.4 of our report (p19), the recommendation rests on a stated premise and a condition—"Since OPG uses the same range of stretch factors in the RRF as distribution utilities, if the OEB believes OPG has similar efficiency opportunities as distribution utilities operating under Custom IR". The recommendation does not assume the OEB has reached that conclusion.

Ontario Power Generation Interrogatory # M4-OPG-017

Interrogatory

Question(s):

Please specify where in the workpapers PEG provides a version of Table 2 (as seen on page 52 of Exhibit M4, Tab 1), with all the formulas and links to source data intact.

Response:

Please see the tab Table 2 in the file labeled 4. Framework Report in the PEG Working Papers. Please note that access to the PEG Working Papers is limited to individuals who have signed the OEB's Declaration and Undertaking in this proceeding.

Ontario Power Generation Interrogatory # M4-OPG-018

Question(s):

Is the input/cost data collected and compiled for PEG's TFP research the same data that was used in PEG's benchmarking research? If it is not the same, please identify all differences.

i. Is the historical O&M and capital cost data deflated into real dollar terms? Which specific year of real dollar terms is all the data represented?

ii. Is the capital cost data estimated pursuant to PEG's assumptions on geometric decay, use of HWI, and the implied rental price of capital?

Response:

i. Yes. The cost data were converted to real dollar terms using the price indexes provided. The specific year is not relevant for the TFP trend research because only the growth rates matter. For cost benchmarking, the choice of year is also somewhat arbitrary, but PEG chose 2021 to make the price level comparisons between the US and OPG and then used the corresponding trend indexes to populate the values for other years. We say "somewhat arbitrary" because differences in the growth of the trend indexes used to determine the values of other years may result in different price ratios in earlier and later years than would be obtained if the price level comparison was done in a year other than 2021 (e.g., a direct price level comparison in 2023 may result in different relative prices than 2023 values obtained by escalating the 2021 comparison for price changed in 2022 and 2023). One must choose between having an accurate price trend and accurate price levels in each year. PEG chose to have accurate levels in a recent year and then rely upon accurate trends to obtain consistent values for other years.

ii. Yes.

Ontario Power Generation Interrogatory # M4-OPG-019

Question(s):

Please confirm that for PEG's TFP research, PEG used an index based technique, rather than an econometric technique, to establish the average TFP trends for the hydroelectric industry that are documented in Table 10 on page 97 of Exhibit M4, Tab 2.

i. Please confirm whether a TFP study using an index technique calls for a scale variable or an output quantity variable.

Response**:**

PEG used productivity indexes to compute annual productivity growth rates for each sampled utility and then computed cost-weighted averages of these. Due to the volatility of O&M input growth and the relatively small sample of utilities, PEG then used trend regressions to compute industry TFP trends from the average annual growth rates of the sampled utilities.

PEG notes that there is no clear distinction in the literature between "scale" variables and "output" variables. We generally prefer to use the broader "scale" term because it is sometimes desirable in econometric cost modeling, productivity trend research, and the design of attrition relief mechanisms ("ARMs") to use a scale-*related* variable such as generation capacity or distribution line length. Since PEG uses a monetary approach to calculate capital quantities there is no need to hold such variables in reserve for use as capital quantity metrics.

In Section 2.1 of the Appendix PEG provides a lengthy discussion of the output metrics that can make sense in TFP index studies. The fundamental choice is between the billing determinants that drive revenue and the scale-related metrics that drive cost. The trends in these quantities can be quite different. Generation driven by hydraulic, solar, or wind energy are good examples. CDM programs can cause the use of energy distribution systems to grow much more slowly than the number of customers.

Trends in billing determinants are relevant in studies to design *price* cap indexes but industry TFP studies that use billing determinants to measure output contain implicit output differentials that can differ markedly from those facing the subject utility. In that situation it makes sense to use a *cost*-based output index to measure the industry TFP trend and a utility-specific output differential to the price cap index formula.

<u>Ontario Power Generation Interrogatory # M4-OPG-020</u>

<u>Question(s):</u>

See page 7 of Exhibit M4, Tab 2. If the benchmarking analysis was based on an econometric model that had been calibrated for 21 years (2004 to 2024), why is PEG focused on reporting only the last three years of performance (2022 to 2024)?

i. On page 75 of Exhibit M4, Tab 2, PEG writes that it benchmarked OPG only starting from 2016. Please explain how an economic cost model fitted with data from 2004 is appropriate for such an exercise?

ii. Can PEG re-estimate the parameters using only data from 2016 to 2024 and report those?

<u>Response:</u>

i. PEG notes at the outset that it is customary in OEB custom incentive ratemaking ("CIR") proceedings to focus on benchmarking results for the three most recent historical years for which data are available and the years of the proposed CIR plan (in this case 2027-2031).

   Using PEG's benchmarking methodology, which does not, like LEI's methodology, infer cost performance from the parameter estimates for company-specific and time-invariant binary variables, there is no need for the sample period of the econometric cost modelling to match the years for which cost is benchmarked. This allows the model parameter estimates to reflect longer-term relationships between industry costs and scale and other business conditions, while the trend variable captures cost trends common to the industry over the sample period. The reported performance scores then summarize the Company's recent and forecasted performance.

ii. Tables that show the econometric modelling and benchmarking results for the shorter sample period are below. Please note that the shorter period does not produce major changes in parameter estimates (e.g., sign flips or large magnitude changes) in any model. The total cost model parameters are remarkably similar despite the sample size falling to just 189 observations. OPG's estimated cost performance is slightly improved historically and a little worse in the forecasted years. The shortened period for the capital cost model also produces similar parameter estimates and results, with a little more movement in the parameter estimates compared to total cost. OPG's estimated capital cost performance is slightly better in each year. The O&M

model is broadly similar with the shortened sample period but has the most parameter movement. OPG's estimated performance is worse in every year compared with the full sample period model.

Table M4-OPG-020-1

PEG's Econometric Model of Total Hydroelectric Generation Cost 2016-2024

VARIABLE KEY

MW Cap =	Total MW Capacity
Units =	Number of Generator Units
Units Sq =	Number of Generator Units squared
% MW PS =	% MW Pumped Storage
%CH =	% Conventional Hydroelectric pre-1964
CH Gen Age =	Weighted Average CH Generator Age
PlantsRiver =	Number of Plants Run of River
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.591***	66.380	0.000
Units	0.700***	34.487	0.000
Units Sq	0.486***	13.909	0.000
% MW PS	-0.0832***	-10.992	0.000
%CH	0.695***	39.749	0.000
CH Gen Age	-1.282***	-25.759	0.000
PlantsRiver	-0.275***	-19.784	0.000
TREND	0.0255***	9.958	0.000
CONSTANT	17.83***	262.295	0.000

Adjusted R^2	0.975
Sample Period	2016-2024
Number of Observations	189

Table M4-OPG-020-2

PEG's Econometric Model of Hydroelectric Generation Capital Cost 2016-2024

VARIABLE KEY

MW Cap =	Total MW Capacity
MW Cap Sq =	Total MW Capacity squared
Units =	Number of Generator Units
Units Sq =	Number of Generator Units squared
% MW PS =	% MW Pumped Storage
%CH =	% Conventional Hydroelectric MW pre-1964
CH Gen Age =	Weighted Average CH Generator Age
PlantsRiver =	Number of Plants Run of River
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.663***	33.443	0.000
MW Cap Sq	0.0891***	7.108	0.000
Units	0.584***	14.707	0.000
Units Sq	0.303***	5.316	0.000
% MW PS	-0.0468***	-24.349	0.000
%CH	0.949***	103.859	0.000
CH Gen Age	-1.572***	-36.127	0.000
PlantsRiver	-0.245***	-16.200	0.000
TREND	0.0330***	54.435	0.000
CONSTANT	14.97***	1043.385	0.000

Adjusted R^2	0.965
Sample Period	2016-2024
Number of Observations	189

Table M4-OPG-020-3

PEG's Econometric Model of Hydroelectric Generation O&M Expenses 2016-2024

VARIABLE KEY

MW Cap =	Total MW Capacity
MW Cap Sq =	Total MW Capacity squared
Plants =	Number of Plants
Plants Sq =	Number of Plants squared
% MW PS =	% MW Pumped Storage
%CH =	% Conventional Hydroelectric MW pre-1964
PlantsRiver =	Number of Plants Run of River
TREND =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.684***	20.810	0.000
MW Cap Sq	-0.0678**	-2.076	0.038
Plants	0.448***	35.049	0.000
Plants Sq	0.287***	31.199	0.000
% MW PS	-0.210***	-13.952	0.000
%CH	0.104*	1.666	0.096
PlantsRiver	-0.131***	-8.437	0.000
TREND	0.001	0.078	0.938
CONSTANT	17.30***	179.551	0.000

Adjusted R^2	0.939
Sample Period	2016-2024
Number of Observations	189

Table M4-OPG-020-4

Year-by-Year Hydro Generation Cost Benchmarking Results Using 2016-2024 Model

	[Actual - Predicted Cost]		
Year	**Total Cost Benchmark Score**	**Capital Cost Benchmark Score**	**O&M Cost Benchmark Score**
2016	-7.75%	-0.40%	-1.11%
2017	-7.98%	-2.85%	2.70%
2018	-6.39%	-3.77%	6.16%
2019	-9.09%	-4.90%	2.82%
2020	-10.74%	-4.52%	-3.09%
2021	-7.52%	-5.84%	7.22%
2022	-9.50%	-6.62%	8.52%
2023	-5.27%	-2.41%	14.51%
2024	-3.91%	-2.91%	14.37%
2025	*-5.20%*	*-2.74%*	*12.05%*
2026	*-3.32%*	*-2.33%*	*17.41%*
2027	*1.92%*	*-0.71%*	*31.82%*
2028	*7.20%*	*3.59%*	*37.66%*
2029	*11.37%*	*9.58%*	*36.72%*
2030	*14.75%*	*14.76%*	*36.20%*
2031	*16.92%*	*17.93%*	*35.85%*
Averages			
2016-2024	**-7.57%**	**-3.80%**	**5.79%**
2022-2024	**-6.22%**	**-3.98%**	**12.47%**
Forecast Period 2025-2031	***6.23%***	***5.73%***	***29.67%***
CIR Period 2027-2031	***10.43%***	***9.03%***	***35.65%***

Ontario Power Generation Interrogatory # M4-OPG-021

Question(s):

Would PEG characterize its benchmarking research in Exhibit M4 as a form of unbalanced panel regression? What adjustments were made to effectuate correction for the unbalanced panel?

Response:

Yes, PEG's regression analysis used an unbalanced panel. No adjustments or corrections were needed as the estimation method explicitly supports both balanced and unbalanced panels.

Ontario Power Generation Interrogatory # M4-OPG-022

Question(s):

See page 26 of Exhibit M4, Tab 2. The text starting on this page describes the various capital decay (depreciation) profiles under “monetary methods that have been most commonly used in research to design rate and revenue cap indexes”. Based on the logic described on this page and the next page, can PEG confirm that generally for the same starting level of capital stock, the geometric decay profile will produce the smallest estimate in changes in real capital stock over time from capital investment and therefore the smallest change in capital input quantities, and consequently the most positive TFP growth rate, holding all else constant?

Response

PEG’s current thinking is that from the same starting level of capital stock the estimated growth of the stock thereafter will be slower with geometric decay (“GD”). However, please note the following.

- The starting capital stock in a study could in fact be lower with GD either because it is lower in the benchmark year for the start of capital quantity calculations or lower in the first year of the featured productivity trend calculations.
- The GD approach is one of the more sensitive to the size of the stock of old assets relative to the quantity of plant additions. If plant additions are low relative to the size of the capital stock at the start of the featured sample period, the capital quantity will grow slowly, thereby boosting TFP growth. If instead plant additions are high relative to the capital stock at the start of the featured period, the capital quantity will grow more rapidly and TFP growth will be slowed. The sample period for a TFP study could therefore capture a period of high replacement of an unusually aged asset fleet and result in a materially negative TFP trend. PEG has reported negative industry TFP trends in numerous TFP studies.

Ontario Power Generation Interrogatory # M4-OPG-023

Question(s):

Please confirm whether PEG is familiar with regulatory decisions in relation to setting price and/or revenue cap indices that were based on TFP studies for the industry using a one hoss shay method. If PEG is familiar with such regulatory decisions, please list out the regulators and utilities for which this circumstance applied.

Response

Yes. In its first generic Alberta PBR proceeding, the Alberta Utilities Commission ("AUC") approved price cap indexes for power distributors and revenue per customer indexes for gas distributors which relied on a power distributor TFP trend of 0.96%. This trend was drawn from a Commission-sponsored study by NERA that featured a one hoss shay ("OHS") approach to capital cost.[20] There was a flaw in NERA's methodology for implementing OHS, criticized in several proceedings by PEG, that caused an accelerating decline in TFP growth in later years of NERA's lengthy sample period. The Commission's approved TFP trend reflected the productivity trend over the full sample period, as NERA recommended, whereas utility expert witnesses advocated using NERA's methodology except for shorter sample periods during which that methodology yielded negative TFP trends. In the subsequent two generic PBR proceedings in Alberta, parties presented TFP studies with varying approaches to capital cost that included geometric decay ("GD"). In these proceedings, the AUC approved X factors informed by various studies and did not signal a preference for OHS.[21]

When energy distributors (e.g., Boston Gas) first received approval of indexed attrition relief mechanisms in Massachusetts their productivity witnesses typically used GD and that was acceptable to the regulator. Some years later, when indexed attrition relief mechanisms ("ARMs") came back into style in Massachusetts, a witness reported a negative productivity trend on behalf of Eversource Energy using NERA's flawed approach to OHS and a short sample period. The regulator accepted that as well.[22] Witnesses for Massachusetts utilities (e.g., Massachusetts Electric, NSTAR Gas, and Boston Gas) have subsequently tended to use OHS but this may reflect in part a strategy on their part of not "rocking the boat."[23] When a witness next tendered a power distributor productivity study for Eversource in Massachusetts it featured hyperbolic decay, but the ARM subsequently approved was not tied to the results of the TFP study.[24]

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[20] Alberta Utilities Commission Decision 2012-237.
[21] Alberta Utilities Commission Decisions 20414-D01-2016 and 27388-D01-2023.
[22] Massachusetts D.P.U. 17-05, p. 390.
[23] Massachusetts D.P.U. 18-150,19-120, and 20-120, respectively.
[24] Massachusetts D.P.U. 22-22

The New Hampshire regulator recently approved a revenue cap index for Public Service of New Hampshire where the X factor was based on a TFP study featuring OHS.[25] However, no counter study was filed in this proceeding. Thus, OHS was "the only game in town."

PEG also notes that TFP studies based on GD have informed decisions by regulators on X factors in California, Maine, Ontario, and British Columbia as well as in Alberta and Massachusetts.

[25] New Hampshire Public Utilities Commission Docket DE 24-070

Ontario Power Generation Interrogatory # M4-OPG-024

Question(s):

Page 76 of Exhibit M4, Tab 2 specifically states that PEG's research was done using a geometric decay profile for measuring capital input quantities. Did PEG test any other decay specification? If so, please provide the results and work papers.

Response

No. However, PEG might have considered a hyperbolic decay specification if time had permitted.

Ontario Power Generation Interrogatory # M4-OPG-025

Question(s):

On page 65 of Exhibit M4, Tab 2, PEG writes: "This would accordingly have been a good proceeding to explore the intermediate hyperbolic decay (HD) specification." PEG does not present any results with a hyperbolic decay.

i. Why didn't PEG produce results using the hyperbolic decay?

ii. Has PEG ever presented a hyperbolic decay profile in any other testimony for a regulatory proceeding?

iii. What kind of challenges, if any, does PEG anticipate in producing a TFP study with hyperbolic decay specification for the hydroelectric generation industry?

Response

i. PEG did not have time to consider a hyperbolic decay specification.
ii. No. PEG has considered HD but has not been satisfied with the various HD specifications of productivity witnesses that have featured it. We haven't yet taken the time to develop our own HD specification.
iii. PEG has mainly been concerned about the appropriate service price formula and benchmark year adjustment for this specification. We have had inconclusive discussions on HD service price design with the Bureau of Labor Statistics of the U.S. Department of Commerce. BLS uses HD in its sectoral productivity trend studies.

Ontario Power Generation Interrogatory # M4-OPG-026

Question(s):

On page 72 of Exhibit M4, Tab 2, PEG writes that a 15-year average is what it most "often uses … in econometric model estimation". PEG also appears to have focused on a 15-year trend for the TFP research it conducted and presented in its evidence.

i. In Exhibit M4, Tab 2, on page 82, PEG writes that for its independent benchmarking research, it fitted the models over 21 years. How does that reconcile with the preference for 15 years on page 72 on Exhibit M4, Tab 2?

ii. Has PEG tested what the fitted values and benchmarking results would look like if it only used the last 15 years of data to fit its cost models? If so, please provide those results in associated workpapers.

Response

i. PEG used a 21-year sample period in its econometric work for two reasons.
   a. The number of companies in the sample was relatively small and adding years to the sample and this increased the appeal of bolstering the number of observations used to estimate model parameters.
   b. We perceived that hydroelectric generation technology has not changed greatly during the sample period.

   A 15-year sample period has become the norm for productivity trend studies on the grounds that it strikes a reasonable balance between data relevance and the need to smooth data volatility.

ii. Please see the response to M4-OPG-020.

Ontario Power Generation Interrogatory # M4-OPG-027

Question(s):

The value of the trend regression method, as noted on page 49 of Exhibit M4, Tab 2, is to reduce the sensitivity of the long-term average TFP results to the end points under a model using generation as the output measure. Please list other PEG TFP studies where PEG has calculated and recommended use of the trend regression results.

Response

PEG has not used trend regressions in other studies. Several reasons for its use in this proceeding by PEG merit note.

- Most of PEG's productivity trend studies have pertained to gas or electric power distribution. In these studies, the need for special smoothing techniques is lessened by the much larger number of sampled companies and the use of the number of customers as the featured scale metric.
- Examination of LEI's work in this proceeding alerted PEG to the potential usefulness of trend regressions.
- The Ontario Energy Board is more open to complex empirical methods than are regulators in some other jurisdictions.

Ontario Power Generation Interrogatory # M4-OPG-028

Question(s):

On page 23 and 24 of Exhibit M4, Tab 2, PEG argues in favour of “size weighted averages”. Please refer to the TFP results reported in table 10 on page 97 of Exhibit M4, Tab 2. The text on page 96 of Exhibit M4, Tab 2 says these are “cost weighted” results. In the workpapers “PEG_HydroGen_EconometricCode”, PEG also does “mean scaling” pursuant to notes.

i. For PEG’s TFP research, please clarify what kind of weighting approach was used to get to an industry average TFP growth rate.

ii. For PEG’s benchmarking research, please explain what approach, if any, PEG used for weighting the data in the econometrics and why that is relevant.

Response

i. For its featured productivity trend calculations PEG featured cost-weighted averages of the growth rates of individual utilities. Cost is a reasonable measure of size, so these averages may also be considered to be size-weighted.

ii. PEG’s regression approach implicitly gives the same weight to the data for each company. The mean scaling procedure referenced does not affect benchmarking results. Its purpose is to aid interpretation by expressing the model parameter estimates at the sample mean values of the variables.

Ontario Power Generation Interrogatory # M4-OPG-029

Question(s):

Please confirm that OPG is included as part of the industry average for PEG's research of industry TFP and specifically as part of the results in Table 10, page 97 of Exhibit M4, Tab 2.

Response

Not confirmed. OPG was included in the sample for econometric model estimation but not in the sample for the industry TFP trend. The TFP calculations for OPG were, however, provided in the working papers file name "2. OPG Data 1.xlsx" in the worksheet "Productivity."

Ontario Power Generation Interrogatory # M4-OPG-030

Question(s):

PEG is proposing an output index for the TFP study that is based on capacity, instead of actual billing determinants that would apply to OPG's hydroelectric CIR plan. On page 18 of Exhibit M4, Tab 2, PEG asserts that the "output differential" is "close to zero".

i. Please reconcile the statement with the analysis that PEG performed and documented on page 57 of Exhibit M4, Tab 2, where PEG estimates that there is a positive differential of 0.11% under the trend regression method but reported to be -0.17% for 15 years under the average annual growth rate method.

ii. Does PEG believe that a differential of 0.11% or -0.17% is immaterial and should be treated as zero?

iii. If already provided, please identify the exact location in the workpapers where PEG provides the calculation with all formulas intact for Table 2 on page 58 of Exhibit M4, Tab 2. If such information does not exist in the workpapers circulated, please provide an additional workpaper including all formulas and links intact.

iv. Please reconcile this observation on page 19 of Exhibit M4, tab 2 about a small and insignificant output differential with what is observed from PEG's TFP research and specifically the results for the "multifactor productivity" for capacity and volume that is reflected in Table 10 on page 97 of Exhibit M4, Tab 2. For example, under the trend regression for the last 15 years, PEG reports multifactor productivity for the industry is estimated at -0.47%. However, for the same industry and same timeframe, PEG reports a multifactor productivity growth rate of -1.69% is estimated if using volume.

v. Please provide examples of other TFP studies that have included an "output differential".

vi. Has PEG explored how generation varies with capacity for each of the plants and for each of hydroelectric operators included in PEG's research of TFP and benchmarking over the study timeframe? If PEG has examined this, please provide PEG's observations and accompanying workpapers.

Response

i. PEG notes at the outset that the -0.17% result was the fifteen-year average annual growth rate ("AAGR") of the output differential. Given the volatility of the output differential growth rate, PEG believes that the AAGR for a 15-year period is not a reliable trend indicator. PEG in any event believes that an output differential trend of 0.10% or less in absolute value is “close to zero.”

ii. Upon further reflection, PEG believes that a 0.10% output differential that slows the growth of OPG’s rates is reasonable. Please see our response to M4-CCC-1 for further details.

iii. Please see the tab OPG Output Growth in the file 5. Report Tables in the PEG Working Papers. Please note that access to PEG’s Working Papers in this proceeding is limited to individuals who have signed the OEB’s Declaration and Undertaking in this proceeding.

iv. PEG acknowledges that the output differential would be a much bigger concern were generation volume used to measure industry output since in that event there would be a large implicit output differential in the -1.69% TFP trend that is not relevant to OPG. The industry productivity trend would thus be irrelevant as well.

v. PEG notes at the outset that where an output differential is implicitly or explicitly used in the design of a rate or revenue cap index it is typically not part of the TFP trend calculation. A good example is the current CIR proposal of Alectra Utilities.[26] Alectra proposes a Custom Price Cap Index with a 0% Productivity Factor that reflects PEG’s 2013 productivity study for OEB Staff. In the 2013 study PEG used a cost elasticity-weighted output quantity index. Alectra’s rate escalation formula also contains a Revenue Growth Factor that effectively establishes a hybrid ARM design. OM&A revenue would be escalated for growth in Alectra’s operating scale using a cost elasticity-weighted scale index. Capital revenue would be escalated by the forecasted growth in capital cost. Capital and OM&A *revenue* escalation would then be converted into *rate* escalation by removing Alectra’s forecast revenue growth from billing determinant growth.

PEG has discussed the usefulness of output differentials in price cap index design in some prior IR proceedings. Most notable, perhaps, was a 2007 proceeding to determine IR plans for Enbridge Gas Distribution and Union Gas. In that proceeding, PEG proposed price cap index formulas in which the industry TFP trend was measured using cost elasticity-weighted scale indexes and the formula also included output differentials called average use factors. These factors differed between the two companies.[27] PEG also proposed an output differential in 2013 direct testimony for Central Maine

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[26] See Exhibit 1, Tab 11, Schedule 1 in EB-2025-0252.

[27] See Mark Newton Lowry, David Hovde, Lullit Getachew, and Steve Fenrick, *Rate Adjustment Indexes for Ontario’s Natural Gas Utilities*, November 2007 pp. 28-31 and 66.

Power and calculated output differentials in 2011 testimony for the Gaz Metro task force and 2012 testimony for Gaz Metro.

vi. Please see table M4-OPG-030 below. It can be seen that in the aggregate the trends in capacity factor for the rest of the sample appear dissimilar to OPG's trends. When disaggregated, the trends in the Eastern parts of the U.S. are much more similar to OPG's than they are to those of the Western U.S.

Table M4-OPG-030

Average Capacity Factor of Operational Units
(weighted by total capacity)

Year	Sample	OPG	Western	Non-Western	W of Mississippi	E of Mississippi
2005	44.0%	55.2%	51.3%	38.3%	51.8%	37.0%
2006	41.9%	56.2%	55.8%	27.5%	56.8%	21.7%
2007	39.8%	54.0%	40.9%	37.5%	44.3%	31.9%
2008	32.1%	61.0%	42.7%	21.8%	46.2%	16.6%
2009	41.4%	60.0%	46.3%	35.7%	50.1%	29.6%
2010	39.4%	50.5%	47.1%	31.3%	50.6%	25.6%
2011	39.5%	54.0%	55.6%	24.1%	57.8%	19.4%
2012	32.7%	50.6%	43.0%	22.6%	45.3%	18.7%
2013	38.7%	53.9%	37.9%	37.9%	41.0%	34.2%
2014	32.4%	54.3%	34.6%	29.9%	36.8%	26.5%
2015	31.7%	54.3%	31.1%	31.4%	34.5%	26.9%
2016	34.9%	52.8%	40.4%	29.6%	42.9%	25.6%
2017	38.0%	55.1%	49.6%	27.5%	51.9%	23.1%
2018	41.0%	53.4%	42.2%	39.5%	43.3%	35.8%
2019	40.5%	57.4%	46.1%	35.1%	48.4%	30.3%
2020	39.2%	58.4%	36.6%	40.5%	40.0%	35.9%
2021	32.6%	55.5%	31.4%	32.9%	34.9%	28.8%
2022	31.5%	60.8%	34.0%	28.7%	36.6%	25.3%
2023	30.5%	59.5%	37.4%	24.1%	38.7%	21.6%
2024	33.9%	NA	37.7%	29.7%	40.4%	26.7%
Averages						
2005-2023	36.9%	55.6%	42.3%	31.4%	44.8%	27.1%
2009-2023	36.3%	55.4%	40.9%	31.4%	43.5%	27.2%
Trend Regressions						
2005-2023	-0.38%	0.13%	-0.80%	0.01%	-0.79%	0.08%
2009-2023	-0.21%	0.19%	-0.72%	0.28%	-0.78%	0.41%

Full Sample: Alabama Power, Southern California Edison, Pacific Gas & Electric, PacifiCorp, Minnesota Power, Public Service Company of Colorado, New York State Elec & Gas, Georgia Power, South Carolina Electric & Gas, Green Mountain Power, Idaho Power, Avista, Ameren Missouri, Rochester Gas & Electric, Duke Energy Progress, Duke Energy Carolinas, Virginia Electric & Power, Portland General Electric, Appalachian Power, Puget Sound Energy

Non-Western: Alabama Power, Minnesota Power, NYSEG, Georgia Power, South Carolina Elec & Gas, Green Mountain Power, Ameren Missouri, Rochester Gas & Electric, Duke Energy Progress, Duke Energy Carolinas, VEPCO, Appalachian Power
E of Mississippi River: Alabama Power, NYSEG, Georgia Power, South Carolina Elec & Gas, Green Mountain Power, Rochester G&E, Duke Energy Progress, Duke Energy Carolinas, VEPCO, Appalachian Power

Ontario Power Generation Interrogatory # M4-OPG-031

Question(s):

Please confirm whether PEG agrees with the following definition for generating capacity: a measurement of potential production capability.

Response:

PEG confirms that this is a reasonable definition, although a more common definition is "the maximum electric output that a power plant can produce in a short time interval." The use of the word "potential" conveys the notion that operation near full capacity may be infrequent or difficult to sustain. However, since the marginal cost of hydro generation is, like that of wind and solar-powered generation, relatively low, the likelihood of the generation unit operating near full capacity is chiefly limited by the availability of the energy source. In this regard, hydroelectric generation is similar to a highway bridge. The bridge can handle traffic most of the time that is close to its capacity, but its use depends on how many motorists choose to cross it.

Ontario Power Generation Interrogatory # M4-OPG-032

Question(s):

On the top of page 19 of Exhibit M4, Tab 2, PEG provides a conceptual formula for an OM&A only revenue cap. The formula in equation [15a] refers to an industry TFP trend. If this is truly just a revenue cap for OM&A, should the TFP component in the formula be replaced with a partial factor productivity (PFP) component that represents OM&A only?

Response:

PEG notes that it is mathematically legitimate to use the TFP trend in separate ARMs for OM&A and capital, and the simplicity of this approach is especially appealing when the partial factor productivity trends of OM&A and capital are similar. Since the focus of the section is the handling of negative productivity trends, we decided not to introduce the complication of PFP trends there.

Ontario Power Generation Interrogatory # M4-OPG-033

Question(s):

PEG used a benchmark year of 1964 as stated on page 76 of Exhibit M4, Tab 2.

i. Where did PEG source the data and check the quality of the data for this benchmark year, given FERC Form 1 was not digitized before 1994?

ii. Please describe how this choice of a 1964 benchmark year would impact directionally the estimate of capital input quantities for PEG's research into industry TFP trends.

iii. Please confirm that this benchmark year also impacts the annual capital cost values used in PEG's benchmarking research.

Response:

i. In the late 1990s, PEG obtained photocopies of the Form 1 pages with accumulated depreciation from 1964 and 1965 for all filers from a company that made copies of physically-archived Federal documents.

ii. We presume this question is using a benchmark year later than 1964 as the counterfactual. PEG believes it is not possible to determine how a more recent benchmark year affects the direction of capital input trends in the recent years used to measure TFP. In general, the higher the capital stock in the first year of the TFP period, the higher should be the productivity growth trend because the identical quantities of plant additions will be smaller in proportion to the initial capital stock and therefore the capital quantity will grow more slowly. The problem is that it cannot be known if the capital stock at the start of the TFP period will be higher or lower if a benchmark year after 1964 is used. This will depend upon the ratio of the real additions after each benchmark year to the benchmark capital quantity, the effect of the decay rate, and the accuracy of the implicit estimate of the additions that results from moving up the benchmarking obtained from the new triangularized weighted average of construction costs to a more recent year. Overall, the use of the oldest possible benchmark year will produce the most accurate capital quantity values because there is less reliance on the inherently inaccurate benchmark year calculation. The statistical benchmarking consultant to several Ontario power distributors (Clearspring) uses a benchmark year that is older than PEG's.

iii. This statement is confirmed.

Ontario Power Generation Interrogatory # M4-OPG-034

Question(s):

On page 40 of Exhibit M4, Tab 2, PEG describes an adjustment that it made to OPG’s historical cost data to reflect the presence of certain “equipment associated with step up functions”. Please provide a detailed written explanation and identify where in PEG’s workpapers there are intact formulas that represent how PEG implemented this adjustment in both its TFP and benchmarking research. If such information does not exist in the workpapers circulated, please provide an additional workpaper including all formulas and links intact.

Response:

A 2.5% adjustment was done based the OPG’s response to Staff-329 (g). The adjustment was done in the “2. OPG Data” file in cell AL3 on the OPG Calculations worksheet. This value was used in to reduce OPG O&M and capital values in columns I and AE. This reduction represents an estimate of cost incurred by OPG not recorded by US companies as part of hydroelectric cost.

Ontario Power Generation Interrogatory # M4-OPG-035

Question(s):

Based on the data that PEG chose to use to develop its cost benchmarking research, PEG appears to believe that FERC Form 1 and EIA data for hydroelectric generation are adequate to allow for robust benchmarking of costs between firms. What research or analysis did PEG conduct to confirm this?

Response:

PEG presented results of its review of the pros and cons of U.S. hydroelectric generating data on pages 40-42 of its Appendix document.

Ontario Power Generation Interrogatory # M4-OPG-036

Question(s):

For PEG's independent benchmarking research and specifically the resulting total cost models represented in Tables 5, 6, and 7, on pages 85, 87, and 89 of Exhibit M4, Tab 2, were those fitted parameters based on data that also includes OPG?

Response:

Yes. OPG was one of twenty-one companies contributing data to the estimation of PEG's econometric benchmarking models. In contrast, PEG understands that OPG accounted for approximately 1/5 of the observations used in the development of its own benchmarking models.

Ontario Power Generation Interrogatory # M4-OPG-037

Question(s):

PEG reports the results of its total cost, capital cost, and O&M models in Tables 5-7 of Exhibit M4, Tab 2.

i. Please explain why PEG used “Number of Generator Units” as a variable in the total cost and capital cost models, but “Number of Plants” in the O&M model. What is the economic intuition behind using different explanatory variables?

ii. Please explain why the “Weighted Average Conventional Hydroelectric Generator Age” variable was included in the total cost and capital cost models, but not in the O&M model.

Response:

i. Differences in the business condition variables featured in PEG’s econometric models reflect differences in the statistical support for these variables. We often find that our disaggregated O&M and capital cost models have a handful of meaningful and plausible differences in the estimated importance of business condition variables. To preserve degrees of freedom, PEG typically excludes business condition variables from benchmarking models if their parameters lack statistical significance.

   We do not think it is unintuitive that the total number of generator units would be less relevant to O&M cost and that the number of plants is the more relevant cost challenge. We suspect that the “Number of Generator Units” variable performs poorly in the O&M model due to the opposite effects of having to operate and maintain numerous units and the O&M savings available to plants with many generator units at the same location.

ii. This variable was statistically insignificant in the O&M model. The percent capacity pre-1964 variable thus seems to capture the age-driven O&M cost pressures. These results are intuitively appealing.

Ontario Power Generation Interrogatory # M4-OPG-038

Question(s):

FERC Form 1 data for hydroelectric generation is available at the plant level. Was PEG's econometric models for benchmarking based on regressing costs against explanatory variables at the individual plant level, or at the company level?

i. Please explain the step-by-step process by which PEG gathered and aggregated the raw cost data.

ii. If plant-level data transformation to company-level information has already been provided in workpapers, please identify the file.

Response:

i. PEG used data at the company rather than the plant level. Utilities report data on the aggregated O&M and capital costs of their hydroelectric production on FERC Form 1. We have never gathered the hydroelectric generating plant, pumped storage, or small generating plant statistics for individual plants that are gathered on FERC form 1. Reasons for this include high incremental cost, our skepticism about the reasonableness of cost breakdowns between plants, and the difficulty of combining these data with a monetary approach to the calculation of capital cost.

   Data for recent years have been drawn directly from utility reports to the U.S. government. PEG downloads the data directly from the FERC for the Form 1 schedules it uses in it practice. The data items are labeled using PEG naming conventions and PEG ID numbers are assigned to replace the FERC ID numbers. Relational database tools similar to SQL are used to assemble the database for additional analysis. Data for years prior to 1995 have been entered manually based on books published by the EIA and predecessor agencies. These are mainly the gross plant additions data needed for capital cost calculations.

ii. Not applicable. Please see the response to part (i) of this question.

Ontario Power Generation Interrogatory # M4-OPG-039

Question(s):

On page 68 of Exhibit M4, Tab 2, PEG writes: "This estimate of the labor cost share cannot be vetted and is out of line with US power generation experience."

i. Can PEG confirm that labour costs are not typically reported in FERC Form 1 for hydroelectric generation?

ii. How does PEG then come to its conclusion that LEI's assumption is "out of line"?

Response:

i. PEG noted on p. 42 of its Appendix that FERC Form 1 does not itemize the salaries and wages attributable to hydroelectric generation.
ii. The estimate used by LEI was 62% (15.3%/(15.3%+9.3%)). This is much higher than the 37% that PEG estimated using US power production salaries and wages. PEG used OPG provided data to obtain a 53% value that reflects the removal of items such as pensions, benefits, and payroll taxes.

Ontario Power Generation Interrogatory # M4-OPG-040

Question(s):

PEG writes on page 72 of Exhibit M4, Tab 2 that: “To be included in the study, the data also were required to be a good quality and plausible”.

i. What steps did PEG take to screen the data for “quality” and “plausibility”?

ii. Please provide workpapers as relevant for such a screening analysis.

Response:

i. PEG examines the data and looks for large changes in the values of variables that might be expected to not change much on a yearly basis. An example is the number of customers served in an energy distribution study. A large change in this variable might indicate that a merger has taken place or perhaps there is some double counting of bundled and delivery customers. These sorts of observations generate additional investigation to determine if a correction, alternative source, or imputation is reasonable solution. A company might be excluded from the analysis if such a solution cannot be found. An example from our power distribution work of data that is plausible but not good quality are the distribution O&M expenses of some California distributors that had extreme wildfire damage. The inclusion of these data hampers efforts to estimate good cost models and productivity trends of typical distributors. There is not enough information to make a credible adjustment to the data and be able to claim the wildfire effects have been removed. Therefore, these data have been excluded from the analysis.
ii. Working papers do not exist for this routine data examination.

Ontario Power Generation Interrogatory # M4-OPG-041

Question(s):

Table 4 on page 73 of Exhibit M4, Tab 2 contains the list of companies used in PEG's research for both the TFP and benchmarking analysis. Has PEG examined the institutional, regulatory, or commercial environments in which these companies operate their hydroelectric business? If yes, please provide the detailed findings of PEG's examination and any associated workpapers.

Response:

PEG personnel have been working with data from these utilities for more than 30 years. Eleven of the companies have been clients. PEG has also prepared detailed, authoritative surveys of the evolution of U.S. electric utility regulation for the Edison Electric Institute. We therefore know quite a bit about the institutional, regulatory, and commercial environments in which the sampled utilities operate. Here are some notable observations.

- Most of the sampled utilities in our study for this proceeding are extensively engaged in generation as well as transmission and distributor services.
- Some utilities (e.g., those in California and New York) sold or spun off most of their generation capacity but continue to own and operate hydro generating stations.
- The retail ratemaking of the sampled utilities ranges from formula rates (e.g., Alabama) to multiyear rate plans (e.g., California and New York).

<u>Ontario Power Generation Interrogatory # M4-OPG-042</u>

<u>Question(s):</u>

On page 75 of Exhibit M4, Tab 2, PEG states: "Prices that utilities pay for hydroelectric generation inputs are likely roughly proportional to those paid for distributor inputs." Please provide the empirical evidence that PEG relied on to support this statement.

<u>Response:</u>

PEG explains on page 75 of its Appendix some reasons why its levelization of labor prices is similar to the labor price levelizations in its power distribution benchmarking studies. In this discussion, PEG stated that

> Prices that utilities pay for hydroelectric generation inputs are likely roughly proportional to those paid for distributor inputs

when it should have said that

> Prices that utilities pay for hydro generation *labor* are likely roughly proportional to those that they paid for other kinds of *labor*.

For example, PEG considers it likely that prices paid for hydro generation labour in California and New York are higher than those paid in Alabama, West Virginia, or South Carolina. Please also note that when PEG calculates relative labor price levels of utilities in a particular year, metrics are gathered from several cities in the service territories of most utilities. These metrics are for average electric utility wages that include generation labour and not just those for employees providing distributor services. We also note on page 75 of the Appendix that a sizable portion of hydroelectric generation labor often occurs in the larger cities that utilities serve. For example, we believe that many of OPG's hydro workers work in metro Toronto.

Ontario Power Generation Interrogatory # M4-OPG-043

Questions:

On page 76 of Exhibit M4, Tab 2, PEG discusses how costs were calculated. This section falls under Chapter 7.2 which is entitled “Variables used in PEG’s benchmarking models”.

i. Why was 1985 chosen; why not 1987 or 1983 or another year?

ii. Please confirm that this calculation applied equally for PEG’s TFP research as well as PEG’s benchmarking research.

iii. Please explain why PEG thought this approach was necessary.

iv. Please specify where in the work papers this “two part” calculation is documented.

Response:

i) 1985 represents a year in which of substantially all of the hydro generation capacity of the US sampled utilities had been added in the US.

ii) Yes. The same method was used for both the TFP and benchmarking studies.

iii) The capital expenditures required after the initial construction of a hydroelectric facility tend to have much shorter average service lives than the very long-lived concrete construction of a dam. The method seeks to assign an appropriate decay rate an HWI to these shorter-lived assets.

iv) Please see the file “3. US Data and TFP”. The worksheets “capital cost old plant” and “capital cost new plant” have the calculations.

Ontario Power Generation Interrogatory # M4-OPG-044

Question(s):

PEG writes on page 78 of Exhibit M4, Tab 2 that it made an ad hoc adjustment to the non-labour portion of O&M input prices: “In the benchmarking work, the levels of utility M&S input prices were assumed to differ in 2019 by 1/3 of the difference between sampled utilities and their corresponding labor prices.”

i. Please provide empirical substantiation for this adjustment by PEG – in other words, how did PEG come up with 1/3?

ii. Why did PEG apply it in 2019?

iii. Was a similar adjustment made to OPG’s cost data?

iv. Does this adjustment also impact PEG’s TFP research?

Response:

i. PEG reasonably assumes that 2/3 of non-labor O&M was purchased services which had a sizable labor component and 1/3 were materials which did not. PEG further assumes that the 1/2 of the labor implicit in purchased services is correlated with local labor market conditions. The product of 2/3 and 1/2 is the source of the 1/3. This approach is an attempt to recognize that the assumption that all companies face the same price level for materials and services is unreasonable and allow the M&S price level to vary a little due to local labor market conditions.

ii. 2019 is the year in which the PEG has data to compare the relative labor prices among US companies.

iii. Yes.

iv. No.

Ontario Power Generation Interrogatory # M4-OPG-045

Question(s):

On page 79 of Exhibit M4, Tab 2, PEG describes employing an index of construction cost levels that varied by service territory of the utilities.

i. Please specify in which workpapers we can see the calculations of this adjustment and how it interacts with the Handy Whitman index.
ii. Why was this applied around 2008 as an anchor year?
iii. Was a similar adjustment made to OPG's cost data?
iv. Does this adjustment also impact PEG's TFP research?

Response:

PEG would not characterize the introduction of a company specific price level to the HW trend indexes as an "adjustment". The asset price indexes constructed from the HW indexes have the same year by year growth rates as the original HW indexes. It could be said that PEG created a new asset price index based on HW indexes and a company-specific location factor from RSMeans that created index numbers that show between company variation from the location factor and the trend from the appropriate regional HW index.

i. Please see worksheets "Capital Cost old plant" and "Capital Cost new plant" in the "3. US Data and TFP" file.
ii. The 2008 values were the same as used in the 2016 version of the work. PEG did not put a priority on updating these values to a more recent year.
iii. Yes.
iv. No. Introducing company specific price levels is not relevant to a trend study and would have no impact.

Ontario Power Generation Interrogatory # M4-OPG-046

Question(s):

On page 81 of Exhibit M4, Tab 2, PEG writes that run of river plants "don't involve dams". How did PEG come to this conclusion?

Response:

We note that the word "typically" appears in the report ahead of the quoted selection, but acknowledge the sentence is imprecise regardless. Run of river hydroelectric facilities, sometimes called "water diversion" facilities, typically do not involve the use of dams to impound large quantities of water in reservoirs. They instead channel a portion of a river of water through a canal and/or penstock to utilize the natural decline in the river bed elevation to produce power. Run of river plants may not have a dam at all, and often require fewer environmental accommodations.

Ontario Power Generation Interrogatory # M4-OPG-047

Question(s):

On page 84 of Exhibit M4, Tab 2, PEG writes: "Total cost was higher the higher was the share of capacity that was established prior to 1964. However, it was lower the higher was the average age of generating stations. This suggests that there was a general tendency of capacity cost to fall with system age until a sizable number of plants had advanced age."

i. Please confirm if there is a typographical error in this text.

ii. Please reconcile the first sentence which refers to total cost, versus the third sentence which refers to capacity cost.

Response:

This is not a typographical error and the sentences can be reconciled. Here are some reasons why.

- The % CH variable captures the importance of *very old* plant while the CH GEN AGE variable captures the *average age* of plant. Please note also that the measure of age is the number of years since the unit was operational and not, for example, the age of generators at the unit.
- The total cost of hydro generation is the sum of O&M and capital costs. Capital costs can reasonably be described as capacity costs (i.e. the cost of capacity ownership).
- Capital cost tends to decline with the average age of generating stations due to depreciation until such time as a sizable share of the assets in the stations are so old as to need extensive repairs, refurbishments, and replacements.
- In much the same way, the average age of a gas distribution network may affect cost but does not by itself do a good job of capturing the cost impact of having a lot of mains that are very old. In gas distribution cost modelling, variables representing the recent prevalence of the older cast iron and bare steel mains tend to have positive and highly significant parameter estimates.

Ontario Power Generation Interrogatory # M4-OPG-048

Question(s):

On page 84 of Exhibit M4, Tab 2, PEG writes: "Total cost was also lower the higher was the share of generating capacity devoted to pump storage…." Please explain the underlying economic intuition for this outcome.

Response:

The importance of pumped storage in a utility's hydro generation mix can affect its cost. However, PEG stated on p. 81 of the Appendix that there was no expected sign for the parameter of the pumped storage variable.

Recall that in an econometric model an individual parameter is estimated in the context of holding all else equal (i.e. the other variables held at their respective means). Increasing the share of capacity that is achieved by pumped storage is estimated to lower cost a bit at the mean values of total capacity and total generation units. Pumped storage is well-known to have comparatively lower evaporation loss and land requirements than conventional hydroelectric generation. A popular academic and energy industry paper topic, pumped storage can also provide particularly valuable efficiency benefits due to its volume flexibility. These benefits can include integration of intermittent resources, capacity optimization, and load balancing services. Pumped storage is also known to have high upfront capital costs, which sheds some light on why the magnitude of the associated (negative) parameter estimate is relatively small in the total and (especially) capital cost models but modestly higher in the O&M cost model.

Ontario Power Generation Interrogatory # M4-OPG-049

Question(s):

Table 5 in Exhibit M4, Tab 2 shows the parameter estimates for various explanatory variables used in PEG's economic model under its benchmarking. Please explain the economic intuition of the parameter estimate and specifically the sign for the %CH variable and the CH Gen Age variable.

Response:

Please see the response to M4-OPG-002.

Ontario Power Generation Interrogatory # M4-OPG-050

Question(s):

On page 90 of Exhibit M4, Tab 2, the last paragraph describes how PEG used a forecast of 2025 to 2031 for “the Company” to benchmark OPG’s cost in the future. Please identify where in the workpapers there are tables with all formulas intact and original raw data (and sources for that raw data) that show how the forecast values used by PEG in the benchmarking were developed from the raw data. If such information does not exist in the workpapers circulated, please provide an additional workpaper including all formulas and links intact.

Response:

Please see the tab OPG Calculations of the file 2. OPG Data in the PEG Working Papers for details on OPG’s forecast data. There are several comments throughout this file with additional details on the forecast data. OPG’s capacity and plant additions data were provided by OPG in its response to Staff-285 part d.

Ontario Power Generation Interrogatory # M4-OPG-051

Question(s):

Please identify where in the workpapers PEG shows how it derived the forecast benchmark scores identified in Table 9 on page 92 of Exhibit M4, Tab 2, with all links and formulas intact. If such information does not exist in the workpapers circulated, please provide an additional workpaper including all formulas and links intact.

Response:

These scores were calculated using the econometric models. The working papers for these models were provided in the compressed file named “1. Econometric”.

Ontario Power Generation Interrogatory # M4-OPG-052

Question(s):

Table 10 on page 97 of Exhibit M4, Tab 2 contains PEG's industry TFP results. Please identify where in the workpapers there is a version of Table 10 that has all working links and formulas intact to other various workpapers with index calculations for PEG's TFP research.

Response:

The values for this table were sourced from the working paper file named "3. US Data and TFP.xls".

CCC Interrogatory # M4-CCC-001

Interrogatory

Reference:

Exhibit M4, p. 40

Exhibit E1 / Tab 1 / Schedule 1 / Table 1

E1-CCC-063 / Chart 1

Preamble:

PEG states that it "agrees that a price cap rather than a revenue cap is warranted for OPG's prescribed hydro generation. This will provide stronger incentives for the Company to maintain or increase its hydro generation volume."

OPG's hydroelectric production forecast for the 2027-2031 period is set out in the table below.

	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Total Regulated Hydroelectric (TWh)	32.5	32.7	33.0	33.0	32.9

Questions:

a) Please advise whether PEG agrees that a price-cap approach that does not reflect an adjustment to reflect the increasing production forecast between 2028-2031 will lead to an over recovery of the hydroelectric revenue requirement (all else being equal).

b) Please advise whether PEG agrees that, in a revenue cap design (which reflects the changing production forecast in each year), OPG will still have an incentive to meet or increase its hydroelectric production forecast. Please consider that if OPG's actual production is below forecast it will under earn (all else being equal) and if its actual production is above forecast it will over earn (all else being equal).

Responses:

a) PEG notes at the outset that price cap indexes approved for use in multiyear rate plans have often been designed without any mechanistic linkage to forecasts of future billing determinants. In such an index, the productivity factor would typically be based on the recent historical trend in the TFP of a sample of utilities using an output metric that tracked the trend in the billing determinants of these utilities. PEG showed in Section 2.1 of the Appendix that a productivity index of this kind contains an implicit output differential defined as the difference between the trends in output metrics that drive revenue and those that drive cost. A difference between these trends can result from many factors that include billing determinants such as volume that are not cost causative and are sensitive to weather, climate, and CDM programs.

   The problem with this approach is that the output differential of the productivity peer group may differ quite a bit from that of the subject utility. This problem can be remedied by measuring the industry productivity trend using a *cost*-based output index like that which would be appropriate for a *revenue* cap index. The revenue cap can then be converted to a *price* cap by adding a company-specific output differential to the formula. Such a differential could in principle be based on the historical or forecasted trends in the output differential.

   A clear example of an output differential in Ontario ratemaking is the current CIR proposal of Alectra Utilities. Alectra proposes a Custom Price Cap Index with a 0% Productivity Factor. A proposed Growth Factor applicable only to OM&A revenue would increase rates based on the average annual forecasted growth in Alectra's operating scale as measured by a cost elasticity-weighted scale index. A Revenue Growth Factor would, among other things, slow rate growth by the forecasted average annual growth in Alectra's billing determinants. The output differential is forecasted in this proposal.

   Other Ontario power distributors (e.g., Toronto Hydro) have had price cap indexes with formulas that explicitly reduced rate growth by the forecasted growth in billing determinants. These plans did not include a corresponding escalation of rates for growth in the number of customers or a more complicated cost-based scale index. Possible reasons for this include the following.

i. Growth in the company's capital revenue was effectively based on a cost forecast, so there was no need to accelerate capital revenue growth for customer growth.

ii. The company was willing to accept slower OM&A revenue growth in appreciation of the forecasting treatment of capital revenue.

iii. The company thought that it could live with I-X escalation for the OM&A component of rates because the I factor was reasonable and the X factor reflected 0% *total factor* productivity growth target whereas *OM&A* productivity *growth* was achievable.

As for the proper output differential for OPG, PEG notes the following.

- The output differential in the case of a hydroelectric power generator can be reasonably approximated by the difference between the growth rates of volume and capacity.

- Table 2 of PEG's Appendix shows that this metric bounces around a fair bit from year to year because the growth of generation volume is volatile. It makes sense to use trend regressions to establish a trend.in volume/capacity.

- The regression over 15 years shows a 0.10% historical trend in the output whereas the regression over 21 years shows a similar 0.11% trend.

- The table also permits consideration of a *forecasted* output differential. The price cap would be operative over the four growth rate years from 2028 to 2031. Over these years, the average annual growth rate of the output differential using volume forecasts in OPG's business plan is forecasted to be 0.12%. This number is sensitive to the 0.92% decline in volume that OPG forecasted for 2027. PEG understands that this decline is due to an increase in planned outages for 2027, as discussed in the Company's response to E1-CCC-063 part b.

PEG concludes on this basis that it would be reasonable for the CCC to request a reduction in OPG's annual rate growth by a further 0.10% from 2028 to 2031. This avoids overrecovery and can be premised on either the historical or the forward looking trend in the Company's generation volume relative to the trend in its capacity.

To illustrate how this would work in practice we provide in the attached spreadsheet deck "PEG_Exh-N_M4_CCC_001_Att-1_OPG and C Factor Calculations Version 2" illustrative calculations of how the output differential and

PEG's proposals for the productivity factor, stretch factor, and a supplemental stretch factor might work. Please note the following.

- To minimize the changes from what OPG proposed (e.g., a C factor tied to the capital revenue requirement) we use an Alectra-style output differential based on OPG's forecasts of generation and volume growth in the last four years of the sample period.
- We assume a -0.47% Productivity Factor, a 0.30% stretch factor, and a 0.30% supplemental capital stretch factor.
- A 0.10% penalty for an incomplete capex forecast could be added if the CCC believes that this is warranted.
- OM&A and capital revenue alike are further escalated by a capacity factor equal to OPG's annual forecasted capacity growth in the last four years of the sample period.
- It can be seen that PEG's proposal would reduce the C factor and slow growth in the price cap index.

b) PEG acknowledges that in the absence of a true-up of revenue to actual sales volumes, revenue caps do afford some incentive to maintain or boost volumes.