

CCC Interrogatory #028

Interrogatory

Reference:

Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 52

Question(s):

- a) Please further explain the statement that “OPG is at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators.” As part of the response, please explain how other North American generators recover their costs and describe any mechanisms that are applied to those generators with respect to true-up production forecasts.
- b) In terms of Concentric’s proxy group, please list all of the peer companies that have no, or less, risk related to the variability of generation output due to rate design or regulatory treatment. As part of the response, please provide a detailed description of the rate design approach or other regulatory treatment that reduces production forecast risk
- c) With respect to the nuclear business, please further explain the change in OPG’s risk related to weather events.
- d) Please provide Concentric’s views on the impact to OPG’s risk of the planned purchase of nuclear business interruption insurance for Darlington beginning in 2027, which the Company has not purchased coverage for in the past.

Response

This response was prepared by Concentric Energy Advisors (“Concentric”):

- a) As noted on page 14 of Concentric’s report (Ex. C1-1-1 Attachment 1), OPG faces revenue risk related to nuclear output variability. OPG is entirely at risk related to variability in the output of its nuclear facilities, which distinguishes it from other regulated utilities, as the companies in the proxy group do not face comparable risk. Concentric elaborates on the risk related to output variability for OPG on pages 27-29 and in Figure 4 of its report.

In contrast, the North American companies in Concentric’s proxy group are primarily vertically integrated electric utilities with generation, transmission, and distribution operations. For these companies, generation-related cost recovery is

1 not generally subject to generation-driven variability. The recovery on and of
2 generation assets is generally established through base rates or riders, while fuel
3 costs, including purchased power and replacement power when generating units
4 are unavailable, are recovered through electric fuel recovery mechanisms, as
5 described on pages 68-69 of Concentric's report.

6
7 Accordingly, base rates for these vertically integrated utilities are not driven by
8 variability in generation output, but rather by changes in customer usage. In
9 addition, many of the proxy group companies have full or partial revenue
10 decoupling mechanisms that further mitigate revenue risk associated with
11 fluctuations in sales volumes due to factors such as weather or changes in
12 customer consumption. As shown in Figure 18 of Concentric's report, 48 percent of
13 the proxy group companies have partial revenue decoupling mechanisms and eight
14 percent have full revenue decoupling.

15
16 b) As discussed in the response to part a), OPG has greater risk related to generation
17 output due to rate design or regulatory treatment than the peer group companies in
18 Concentric's proxy group.

19
20 c) Please refer to the response to Ex. L-C1-Staff-051, part b).

21
22 d) OPG's purchase of nuclear business interruption insurance would provide foregone
23 revenue protection to OPG for business interruptions due to insurable physical
24 damage events at Darlington, to substitute certain revenues lost during the
25 business interruption. However, these payments for business interruption would
26 be subject to a waiting period (typically 120 days) during which OPG would not be
27 eligible for recovery of lost revenues, as well as caps on businesses interruption
28 insurance proceeds that can be recovered.

29
30 Caps on business interruption insurance proceeds would typically include a limit of
31 the maximum lost revenue recovered per day and a maximum indemnity period
32 following the waiting period; these limits apply per nuclear plant covered under the
33 insurance policy and are shared across multiple units. As such, business
34 interruption insurance does not fully indemnify the company, and does not fully
35 protect its debt or equity investors with respect to major unplanned outage events
36 due to physical damage, even if insurance coverage applies.

37
38 Nuclear operators in the United States carry business interruption insurance for
39 physical damage events through mutual insurance provider the Nuclear Electric
40 Insurance Limited ("NEIL"). As such, OPG's purchase of nuclear business
41 interruption service, while reducing OPG's risk related to certain major outages
42 caused by physical damage, would bring OPG into greater alignment with the
43 nuclear operators in the proxy group, all of which operate plants in the U.S.

CCC Interrogatory #032

Interrogatory

Reference:

Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 69

Question(s):

- a) Please provide a definition for each regulatory mechanism listed in Figure 18.
- b) Please provide a table that lists each of peers in the Concentric proxy group and highlights whether each specific peer is applied each of the regulatory mechanisms listed in Figure 18. Please also include OPG (and Concentric's view on the application of these regulatory mechanisms to OPG) in this table.

Response

The response to part a) and a portion of part b) was prepared by Concentric Energy Advisors ("Concentric"):

- a) The definitions for the regulatory mechanism listed in Figure 18 are provided in Regulatory Research Associates' "Adjustment clauses: a state-by-state overview" report, published by S&P Global Capital IQ in September 2025. Concentric has provided those definitions below:
- Electric Fuel Recovery Mechanism: "For an electric utility, a FAC or purchased power clause allows a jurisdictional utility to regularly adjust the price of electricity to reflect fluctuations in the cost of fuel – or purchased power – used to supply that electricity. The calculation methods for FACs can differ significantly across utilities and jurisdictions."
 - Conservation Program Expense: "A conservation program expense adjustment clause is a regulatory mechanism that authorizes utilities to recover costs associated with administering demand-side management ("DSM") and energy efficiency ("EE") programs outside the framework of a general rate case. These programs are often mandated by state law or encouraged through regulatory policies to reduce energy consumption, defer infrastructure investment and support environmental goals."
 - Delivery Infrastructure: "It refers to the physical infrastructure used to transport electricity or natural gas to end-use customers. As utilities enhance and upgrade their distribution systems to meet new reliability, efficiency and policy demand, delivery infrastructure riders ("IR") provide a regulatory avenue for recovering these costs outside the scope of a general rate case."

1 For electric utilities, these mechanisms may facilitate the recovery of
2 expenses related to distribution substations, poles and wires, smart meters
3 and advanced metering infrastructure.”

- 4 • Transmission Costs: “RRA considers a transmission cost adjustment clause
5 as a mechanism allowing a utility to recover costs associated with
6 transmission charges allocated by FERC. These charges typically stem from
7 a utility’s participation in a regional transmission market and reflect its share
8 of a systemwide transmission investment, operational costs, or upgrades
9 constructed and maintained by other transmission owners within the regional
10 transmission organization or independent system operator territory.”
- 11 • Renewable Expense: “It refers to generation facilities that use newer,
12 emerging or policy-driven technologies that differ from traditional,
13 dispatchable generation. These technologies have arisen in response to
14 regulatory mandates, climate policies and evolving market dynamics.
15 Typically, nontraditional generation includes renewable energy resources –
16 solar, wind, geothermal and hydro – alongside energy storage solutions, fuel
17 cells and microgrids. Compared to traditional generation, nontraditional
18 resources are generally quicker to deploy, offer greater flexibility in scale and
19 location, and are often incentivized or mandated through renewable portfolio
20 standards, clean energy standards, tax credits and climate targets.”
- 21 • Partial/Full Decoupling: “A decoupling mechanism is a type of adjustment
22 clause that allows utilities to mitigate the impact of revenue fluctuations
23 caused by changes in sales. These fluctuations may result from customer
24 participation in energy efficiency programs, deviations from “normal”
25 temperature patterns or varying economics conditions. RRA classifies a
26 decoupling mechanism that addresses all these factors as a “full” decoupling
27 mechanism. In contrast, those that only account for one or two factors are
28 labeled as “partial” decoupling mechanisms. Additionally, RRA assigns a
29 partial decoupling designation to mechanisms that incorporate rate caps or
30 other limitations.”
- 31 • Environmental Compliance: “These adjustment clauses allow utilities to
32 recover costs incurred in meeting federal, state or local environmental
33 regulations. These mechanisms can cover a range of expenses, including
34 capital investments in emissions control technologies, operating costs for
35 environmental monitoring, permit compliance, remediation efforts, and
36 upgrades required to adhere to the US Environmental Protection Agency
37 rules and regulations.”
- 38 • Generation Capacity: “It refers to utility-scale power plants that utilize long-
39 established, dispatchable technologies, such as coal, natural gas, and
40 nuclear units. These resources are designed to meet large-scale, aggregate
41 demand and require substantial capital investment, along with extended lead
42 times for planning, permitting and construction. RRA considers a traditional
43 generation adjustment clause a mechanism that permits recovery of the costs

1 associated with the construction of traditional generation capacity. Despite
2 their reliability as power sources, these plants are increasingly subject to
3 economic and regulatory pressures due to rising fuel costs, aging
4 infrastructure and specific environmental policy mandates.”

5
6 b) For the requested table, please see Attachment 1.

7
8 Several of the adjustment clauses and cost recovery mechanisms that have been
9 implemented by the proxy group companies in Figure 18 are applicable to the
10 specific operating environment and risks of those companies, and not directly
11 applicable to OPG, as a generation-only company. OPG has its own deferral and
12 variance accounts that mitigate a number, though not all, of the major risks
13 associated with its regulated nuclear and hydroelectric facilities, subject to the
14 prudence standard. Importantly though, as discussed in the response to Ex. L-C1-
15 CCC-28 (a), OPG does not have regulatory protection against variability in nuclear
16 output, while 56% of the peer group companies have full or partial revenue
17 decoupling mechanisms that reduce volumetric risk. As shown in Figure 18, certain
18 operating companies held by the proxy group have capital cost recovery for
19 generation capacity (24%), transmission costs (55%), and delivery infrastructure
20 (61%). In addition, the peer group companies have recovery mechanisms for
21 environmental compliance costs (41%), renewable expenses (47%), and
22 conservation program expenses (86%). Additionally, unlike OPG, all of the peer
23 companies with electric generation have electric fuel cost recovery mechanisms;
24 OPG is exposed to fuel cost risk, particularly for the regulated nuclear facilities.

25
26 Furthermore, as explained on pages 40-41 of Concentric's report, S&P has
27 indicated that all regulation is considered credit supportive and decreases risk as
28 compared to competitive ventures. While S&P ranks jurisdictions along a
29 continuum from “Credit Supportive” to “Most Credit Supportive,” the rating agency
30 has stated that differences between jurisdictions are a matter of degree.

31
32 *The following response to part b) was prepared by OPG:*

33
34 OPG is not familiar with each of the specific regulatory mechanisms referenced in
35 the question. As a general matter, OPG understands some of these mechanisms
36 to be conceptually similar to deferral and variance accounts in place for its regulated
37 operations, although the specific types of expenditures covered may vary. OPG
38 also observes that, although none is currently in place, it is conceptually possible
39 to have a form of de-coupling mechanism that provides some protection to OPG's
40 regulated nuclear assets against volumetric risk.

1 **CCC Interrogatory #034**

2
3 **Interrogatory**

4
5 **Reference:**

6 **Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 84-86**

7
8 Question(s):

9
10 Please file all the credit agency reports referenced in Appendix B (pp. 84-86 of the
11 report).

12
13
14 **Response**

15
16 *This response was prepared by Concentric Energy Advisors (“Concentric”)*

17
18 Please see Attachments 24 through 35 (Confidential) of the response to Ex. L-C1-
19 SEC-30(b) for the requested credit agency reports.

CCC Interrogatory #037

Interrogatory

Reference:

Exhibit C2, Tab 1, Schedule 1, Table 1

EB-2020-0290, Exhibit C2, Tab 1, Schedule 1, Table 1

Preamble:

The 2022 to 2024 actual total nuclear liabilities are materially different then the forecast 2022 to 2024 nuclear liabilities that were included in OPG's 2022 to 2024 rates.

Question(s):

- a) Using the categories of cost in Table 1, please explain which elements of the nuclear liabilities revenue requirement are ultimately a pass through as a result of the operation of deferral/variance accounts, the ONFA, or other reasons, and which elements of the nuclear liabilities revenue requirement, if any, OPG bears the risk for in the event the actual amount varies from the amount embedded in rates. Please explain which categories are subject to adjustment each time the ONFA is updated.
- b) Please confirm that for elements that are subject to deferral/variance accounts, both positive and negative variances are tracked. If not confirmed, please explain how and why the accounts operate asymmetrically.

Response

- a) Using the categories in Ex. C2-1-1, Table 1, OPG has provided an explanation of which categories of its nuclear liabilities' revenue requirement impact are subject to deferral and variance accounts, below. All of these categories are typically impacted by changes in OPG's nuclear liabilities arising from an approved ONFA reference plan. The requirements of Ontario Regulation 53/05 with respect to OPG's nuclear liabilities are discussed in Ex. C2-1-1, Section 4.1, Section 4.2 and Section 8.0.

None of OPG's nuclear liabilities' revenue requirement impact is recovered under the Ontario Nuclear Funds Agreement ("ONFA").

For clarity, as discussed in Ex. G2-2-1, Section 3.2 and Section 3.3, OPG receives payments from Bruce Power LP for the interim storage and ultimate disposal of

1 used fuel produced by the Bruce nuclear generating stations and the low and
2 intermediate level nuclear waste generated on the associated leased premises by
3 or on behalf of Bruce Power LP. In accordance with Ontario Regulation 53/05,
4 section 6(2)10, these revenues are applied, in full, to reduce OPG's nuclear
5 revenue requirements, as part of Bruce Lease net revenues.

6
7 **Ex. C2-1-1, Table 1 – Prescribed Facilities Line Items**

8 Depreciation of Asset Retirement Costs – this category is subject to the Nuclear
9 Liability Deferral Account when the underlying change in the asset retirement costs
10 (“ARC”) (for OPG's prescribed facilities), as defined in Ex. C2-2-1, occurs as a
11 result of a change in OPG's nuclear liabilities arising from an approved reference
12 plan under the ONFA. The Nuclear Liability Deferral Account is established by
13 Ontario Regulation 53/05, section 5.2(1).

14
15 When a change in the ARC occurs as a result of a change in OPG's nuclear
16 liabilities for another reason, or when there is a change in the end-of-life dates used
17 to depreciate these costs that is not reflected in an approved ONFA reference plan,
18 OPG has been required, pursuant to the OEB's respective payment amounts
19 orders, to file an accounting order application with the OEB to address such
20 impacts, in either case to the extent the resulting revenue requirement impact for
21 OPG's prescribed facilities is \$10M or greater on an annualized basis and is neither
22 reflected in the current or proposed payment amounts nor recorded in a deferral or
23 variance account. As discussed in Ex. F4-1-1, p. 4, lines 16-26, the Application
24 proposes to continue this requirement for the IR term, subject to increasing the
25 \$10M threshold to \$20M consistent with the proposal to increase OPG's overall
26 materiality threshold from \$10M to \$20M in Ex. A1-3-2, Section 4.3. Various deferral
27 accounts have been historically established in view of this provision, including a
28 historical Impact Resulting from Changes to Pickering Station End-of-Life Dates
29 (December 31, 2017) Deferral Account, which this Application requests to
30 terminate, and the Impact Resulting from Optimization of Pickering Station End-of-
31 Life Dates Deferral Account, established in EB-2020-0290. Assuming similar
32 accounts continue to be established in the future pursuant to the accounting order
33 requirement or otherwise, subject to any materiality threshold and together with the
34 scope of the Nuclear Liability Deferral Account, changes in depreciation of asset
35 retirement costs would be subject to deferral and variance account treatment.

36
37 Used Fuel Storage and Disposal Variable Expenses, and Low and Intermediate
38 Level Waste Expenses – these categories are subject to the Nuclear Liability
39 Deferral Account when the underlying change in the asset retirement obligation
40 (“ARO”) (for OPG's prescribed facilities), as defined in Ex. C2-2-1, occurs as a
41 result of a change in OPG's nuclear liabilities arising from an approved reference
42 plan under the ONFA. In such circumstances, the Nuclear Liability Deferral Account
43 records the change in these line items related to a change in the underlying

1 volumetric cost rates, per used fuel bundle or per cubic metre of low level or
2 intermediate level waste (“L&ILW”), as applicable. The Nuclear Liability Deferral
3 Account does not capture changes due to variances in the volume of used fuel or
4 L&ILW. When a change in the ARO for OPG’s prescribed facilities occurs as a
5 result of a change in OPG’s nuclear liabilities for another reason, the changes in
6 underlying volumetric cost rates, but not volumes, are captured in any respective
7 deferral or variance account established by the OEB using the process described
8 above for the ARC depreciation expense.

9
10 Return on ARC in Rate Base – these categories are subject to the Nuclear Liability
11 Deferral Account when the underlying change in the ARC (for OPG’s prescribed
12 facilities) occurs as a result of a change in OPG’s nuclear liabilities arising from an
13 approved reference plan under the ONFA. When a change in the ARC for OPG’s
14 prescribed facilities occurs as a result of a change in OPG’s nuclear liabilities for
15 another reason, the changes in these line items are captured in any respective
16 deferral or variance account established by the OEB using the process described
17 above for depreciation expense. No deferral or variance accounts capture changes
18 in these line items due to other variances from forecast in the ARO or ONFA
19 segregated fund asset values.

20
21 Income Tax Impact – this category is subject to the Nuclear Liability Deferral
22 Account when it changes as a result of variances in other components of the
23 nuclear liabilities’ revenue requirement that are recorded in the account, or due to
24 differences in the amount of OPG’s contributions to the ONFA segregated funds
25 with respect to the prescribed facilities. When a variance in another component of
26 the nuclear liability revenue requirement impact for OPG’s prescribed facilities is
27 subject to a different deferral or variance account established by the OEB using the
28 process described above for depreciation expense, any associated income tax
29 impact is recorded in such same deferral or variance account. No deferral or
30 variance accounts capture changes in this line item due to other variances in the
31 above components or in the amount of OPG’s expenditures on nuclear liabilities or
32 disbursements from the ONFA segregated funds (unless such changes are eligible
33 for the Income and Other Taxes Variance Account (OPG)).

34
35 **Ex. C2-1-1, Table 1 – Bruce Facilities Line Items**

36 All changes in the Bruce Facilities categories, at Ex. C2-1-1, Table 1, lines 9-14,
37 whether arising due to a change in OPG’s nuclear liabilities arising from an
38 approved ONFA reference plan or otherwise, are subject to the Bruce Lease Net
39 Revenues Variance Account established by the OEB to give effect of the
40 requirements of Ontario Regulation 53/05, sections 6(2)9 and 6(2)10. The above
41 requirements with respect to the nuclear liabilities were confirmed by amendments
42 to Ontario Regulation 53/05 made in December 2025 that introduced, among
43 others, section 6(2)10.1. The Income Tax Impact on Revenue Requirement

1 category is not currently subject to any deferral or variance account (unless such
2 changes are eligible for the Income and Other Taxes Variance Account (OPG)).

3

4 The Nuclear Liability Deferral Account is discussed in Ex. H1-1-1, Section 5.14, the
5 Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral
6 Account is discussed in Ex. H1-1-1, Section 5.23 and the Bruce Lease Net
7 Revenues Variance Account is discussed in Ex. H1-1-1, Section 5.16.

8

9 b) Confirmed.