July 31, 2020

Ms. Christine Long
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON
M4P 1E4

Dear Ms. Long:

Re: OPG Reporting and Record Keeping Requirements – July 31, 2020 (Non-Confidential Version)

This submission responds to the OEB's direction in EB-2010-0008 (p. 151) to provide "[a]n analysis of the actual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business and comparison with the regulatory return included in the payment amounts." In EB-2016-0152 (p. 146), the OEB established that this information would be filed by July 31st of each year.

Given the COVID-19 pandemic, the OEB granted an extension from April 30th to July 31st, 2020 for the following materials, in addition to the submission above:

- Information on FTEs, Construction Work in Progress (CWIP) capital and in-service additions (per the OEB's direction in EB-2010-0008, p. 151);
- OPG's MD&A and Financial Statements filed with the OSC, OPG's nuclear unit capability factors and the hydroelectric availability for its regulated facilities (per the OEB's direction in EB-2010-0008, p. 151);
- Performance reports for the nuclear business (per the OEB's direction in EB-2016-0152, p. 151); and
- Performance reports and TGC/MWh for the regulated hydroelectric business (per the OEB's direction in EB-2016-0152, p. 149).

Per the OEB's direction in EB-2016-0152 (Decision and Order, p. 151), OPG intends to file 2020 nuclear performance targets. However, due to changes in certain planning assumptions resulting from the

company's COVID-19 response, OPG is in the process of reviewing the 2020 targets and as such does not provide them at this time. OPG will be including the 2020 targets in its November 2020 submission of the 2020 nuclear performance report with benchmark quartile results.

Please find attached the following information:

OPG 2019 Regulated Return on Equity

1) Table 1 – Summary of Actual Capitalization and Cost of Capital, Year Ended December 31, 2019.

This table shows the capital structure and calculated return on equity based on the information shown in Table 2.

2) Tables 2 and 2a – Actual Regulatory Return on Equity, Year Ended December 31, 2019.

These tables show the calculation of the actual regulatory return on equity.

3) Table 3 – Comparison of Actual Regulatory Return on Equity to Board Approved, Year Ended December 31, 2019.

This table is included for comparison of the actual regulatory return with the regulatory return included in the nuclear payment amount.

Materials Normally Submitted by April 30

4) Table 4 – Full-Time Equivalents (FTEs) by Representation, Years Ended December 31, 2019

This table shows the FTEs broken down by Management Group, Power Workers' Union, and Society of United Professionals for both the regulated Nuclear and Hydroelectric business.

5) Table 5– Continuity of Construction Work-In-Progress (CWIP) and In-Service Additions, Year Ended December 31, 2019

This table shows CWIP and In-Service-Additions broken down by Regulated Hydroelectric, Nuclear, and Corporate Support Services.

6) Table 6– Management's Discussion and Analysis (MD&A), Financial Statements, Nuclear Unit Capability Factors, and Hydroelectric Availability, Year Ended December 31, 2019

This table provides links to the disclosure of OPG's MD&A filed with the OSC, Financial Statements filed with the OSC, Nuclear Unit Capability Factors, and Availability for the Regulated Hydroelectric Facilities.

7) Table 7– Pickering Performance Report, Year Ended December 31, 2019

This table provides the Pickering Performance Report for 2019.

8) Table 8– Darlington Performance Report, Year Ended December 31, 2019

This table provides the Darlington Performance Report for 2019.

9) Table 9– OPG Nuclear Performance Report, Year Ended December 31, 2019

This table provides the Nuclear Performance Report for 2019.

10) Table 10– OPG Regulated Hydroelectric Performance Report, Year Ended December 31, 2019

This table provides the Regulated Hydroelectric Performance Report for 2019.

Confidential Information

We note that under the OEB's Practice Direction on Confidential Filings (the "Practice Direction") and the OEB's Electricity Reporting & Record Keeping Requirements ("Electricity RRR") that certain information filed is treated in confidence by the OEB.

In this RRR filing by OPG, there is OPG confidential information in Tables 2 and 2a. This information relates to margins on sales of surplus heavy water, included in Nuclear revenues, and this same information was afforded confidential protection by the OEB in EB-2010-0008 and subsequent proceedings. The information remains confidential and so a redacted version of OPG's ROE RRR filing is herewith filed for the public record. The redactions are consistent with those made in the EB-2010-0008 and subsequent payment amounts orders. A separate unredacted ROE RRR filing will be simultaneously filed with the OEB in confidence for the OEB's review only.

OPG respectfully requests that prior to any intention the OEB may develop to disclose the confidential information on the public record, that the OEB give OPG notice and afford OPG an opportunity to make submissions on the issue.

OPG's 2019 Regulated Return on Equity Performance

OPG's regulated return on equity (ROE) for 2019 is 15.61% as calculated in Tables 1, 2 and 2a. The 2019 results are 3.45% above OPG's 12.16% dead band, being the ROE of 9.16%[1] approved in payment amounts ±300 basis points.[2] In EB-2016-0152, OPG indicated, that as part of its ROE reporting, if performance is outside of the dead band, it would asses the drivers of the ROE variance and submit an assessment to the OEB[3].

[1] 9.16% is a rate-base-weighted average of the 8.78% ROE approved for the nuclear business in EB-2016-0152 and 9.33% ROE approved for the hydroelectric business in EB-2013-0321.

[2] EB-2016-0152 Decision and Order, Page 134

[3] EB-2016-0152 I-11.7-1 Staff-271

The higher than expected ROE performance in 2019 is primarily attributable to higher nuclear generation due to fewer outage days than planned, reflecting improvements achieved in OPG's nuclear asset management cycle and efficiencies realized in the execution of 2019 planned outages. Despite this higher than planned performance in 2019, the average regulated ROE to date for the 2017-2019 period, at 10.74% as shown in Figure 1 below, and the projected average ROE over the 2017-2021 IR term, at 11.0%, remain within the dead band. Figure 1 also shows OPG's historical regulated ROE performance since inception of OEB's regulation of the prescribed assets, a period over which OPG earned less than 5% on average. A substantial driver of OPG's low historical performance has been variances in nuclear generation given OPG's ongoing risk exposure to the volumetric variable nature of its nuclear payment amounts[4].

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Actual	(3.11)%	1.10%	4.71%	4.80%	4.73%	0.46%	6.32%	3.63%	3.80%	5.91%	10.69%	15.61%
OEB-Approved	8.65%	8.65%	8.65%	9.43%	9.55%	9.55%	9.36%	9.30%	9.30%	9.16%	9.16%	9.16%

Average (2008-2019)
4.89%

Average (2017-2019)
10.74%

Figure 1: Regulated ROE Performance over Time

The Company's response measures to COVID-19 are expected to have an impact on OPG's regulated ROE performance for 2020 and 2021, to the extent currently known or anticipated. The single largest such impact relates to a planned deferral of a Darlington Unit 1 outage (D2011) from the Fall of 2020 to 2021 to support the revised start date of the Darlington Unit 3 refurbishment. While the change in the D2011 timing is expected to increase the 2020 ROE above the 300 basis points dead band, to 12.8%, it will have a corresponding negative effect on the 2021 ROE, which OPG expects to be slightly below the OEB-approved ROE, at 9.0%. As a result, the projected average performance over both the 2020-2021 period and over the full 2017-2021 rate term period will remain within the dead band, at 10.9% and 11.0%, respectively. Had the D2011 outage remained in 2020, the projected performance for 2020 and 2021 would be within the dead band at approximately 11.0% for each year.

[4] EB-2016-0152, E2-1-1, Chart 2

The projections noted in the preceding paragraph include the revisions to the Darlington refurbishment schedule itself, including Unit 2 returning to service on June 4, 2020 and Unit 3 coming offline at the end of July 2020 to commence a planned outage immediately preceding the start of refurbishment.

OPG continues to monitor and assess potential future COVID-19 impacts and risks, which may negatively impact regulated ROE performance as the pandemic evolves. Due to an inherent inability to predict such impacts, they are not reflected in the projections provided. Some of the risks being monitored related to execution of nuclear outages and other work programs include extent and duration of physical distancing requirements and other enhanced safety measures, and potential impacts on vendors and supply chains.

Based on the assessment above, OPG's 2019 results represent a short term variance in the ROE and as such OPG's payment amounts continue to remain just and reasonable for the remainder of the IR term.

Yours truly,

Matt Kirk

Att.

cc: Cathy Nguyen, OEB
Stephanie Chan, OEB

Numbers may not add due to rounding.

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Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2019

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1, 2	139.9	1.3%	1.96%	5.1
2	**Existing Long-term Debt**	1	3,961.3	36.0%	4.33%	171.4
3	**Other Long-term Debt Provision**	1, 3	1,947.0	17.7%	4.33%	84.2
4	**Total Debt**	4	6,048.2	55.0%	4.31%	260.7
5	**Common Equity**	4, 5	4,948.5	45.0%	15.61%	772.4
6	**Rate Base Financed by Capital Structure**	4	10,996.7	95.7%	9.39%	1,033.1
7	**Adjustment for Lesser of UNL or ARC**	1	488.5	4.3%	4.93%	24.1
8	**Rate Base**	1	11,485.1	100.0%	9.20%	1,057.2

Notes:
1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2016-0152.
2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
3 Debt required to balance capital structure with actual rate base.
4 Capital structure as approved by the OEB in EB-2016-0152.
5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

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Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2019

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	620.3	524.7	1,145.0
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.4	0.0	0.4
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		619.9	572.3	1,192.2
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	176.3	84.4	260.7
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	24.1	24.1
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	11.0	36.3	47.3
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		454.6	500.1	954.7
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	83.7	98.6	182.3
13	**Regulatory Return on Equity** (line 11 - line 12)		370.9	401.5	772.4

See Table 2a for notes

Numbers may not add due to rounding.

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Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2019
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2015 audited financial statements for OPG's prescribed facilities filed in EB-2016-0152 Ex. A2-1-1, Attachment 5.

2 During 2019, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2019 reflected in the EB-2016-0152 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2019 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2016-0152, as follows:

Table to Note 4 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	4.31%	4.31%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,437.9	4,047.2
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	488.5
4a	Rate Base Financed by Capital Structure	7,437.9	3,558.8
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,090.8	1,957.3
7a	Cost of Deemed Debt for Regulated Assets	176.3	84.4
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	24.1
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account recorded in 2019.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of the 2019 nuclear tax loss forecasted in EB-2016-0152 to be carried forward beyond the 2017-2021 period. The amount of regulatory income taxes reflects the actual 2019 income tax return completed in June 2020. Consistent with OPG's EB-2016-0152 Reply Argument, p.173, footnote 94, starting in 2017, the regulatory income tax calculation reflects Scientific Research & Experimental Development investment tax credits in the amount earned for the year (at the applicable accounting recognition percentage).

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Table 3
Comparison of Actual Regulatory Return on Equity to Board Approved for Nuclear ($M)
Year Ended December 31, 2019

Line No.	Description	Note	OEB Approved[2]	Actual	(b) - (a) Variance
			(a)	(b)	(c)
	Revenues:				
1	**Revenue Requirement**	1	3,216.1		
2	**Ancillary and Other Revenue**	1	[redacted]		
3	**Bruce Lease Revenues Net of Direct Costs**	1	(20.6)		
4	**Amortization of Variance & Deferral Account Amounts**		108.9		
5	**Total Revenues** (lines 1 through 4)	2	[redacted]	[redacted]	[redacted]
	Expenses:				
6	**OM&A**	1, 3	2,305.4	2,200.8	(104.6)
7	**Fuel**	1	217.1	239.4	22.3
8	**Depreciation & Amortization, including Amortization of Variance & Deferral Account Amounts**	4	512.6	605.3	92.7
9	**Property Taxes**	1	15.3	12.5	(2.8)
10	**Total Expenses** (lines 6 through 9)		3,050.3	3,058.0	7.7
11	**Other Losses/(Gains)**		0.0	0.4	0.4
	Cost of Capital Excluding Return on Equity:				
12	**Cost of Deemed Debt for Regulated Assets**	5	75.7	84.4	8.7
13	**Adjustment for Lesser of UNL or ARC**	1, 6	17.7	24.1	6.4
14	**Cost of Capital Variance and Deferral Account Additions**	7	0.0	(36.3)	(36.3)
15	**Total Cost of Capital Excluding Return on Equity** (lines 12 through 14)		93.3	72.2	(21.2)
16	**Income Tax**	1, 8	[redacted]	98.6	[redacted]
17	**Reporting Adjustment**	9	N/A	[redacted]	N/A
18	**Regulatory Return on Equity** (line 5 - line 10 + line 11 - line 15 - line 16 + line 17)	1, 10	203.4	401.5	198.1

Notes:

1 OEB-approved amounts are the sum of corresponding amounts in EB-2016-0152 Payment Amounts Order, App. A, Table 3 (2019 Nuclear).

2 Actual amounts in col. (b) includes the adjustment to remove the revenue component of the shareholder portion of heavy water sales net of costs for Nuclear shown in Table 2, line 5.

3 Actual amount in col. (b) includes the adjustment to remove the cost component of the shareholder portion of heavy water sales net of costs shown in Table 2, line 5.

4 OEB Approved amount in col. (a) is calculated as the sum of line 17, col. (c) in EB-2016-0152 Payments Amount Order, App. A, Table 3, plus line 4, col. (a) above. Actual amounts in col. (b) include the amortization adjustment shown in Table 2, line 6.

5 OEB Approved amounts are the sum of short-term debt cost and long-term debt cost from the EB-2016-0152 Payment Amounts Order (App. A, Table 3, lines 10 and 11). Actual amounts are from Table 2, line 8, col. (b).

6 Actual amount in col. (b) from Table 2, line 9, col. (b).

7 Actual amount in col. (b) from Table 2, line 10, col. (b).

8 Actual amount in col. (b) from Table 2, line 12, col. (b).

9 The Reporting Adjustment line is included solely to maintain the confidentiality of the amount of actual heavy water sales net of costs.

10 Actual amount in col. (b) are as shown in Table 2, line 13, col. (b).

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Table 4
Full-Time Equivalents (FTEs) by Representation
Year Ended December 31, 2019

Representation	Nuclear[1,2]		Regulated Hydro[1,2]		Total
	Regular	Non-Regular	Regular	Non-Regular	
Management Group	891	61	140	5	1,097
Power Workers Union[3]	3,376	1,542	657	41	5,616
Society of Energy Professionals	2,508	250	392	14	3,164
Total	6,775	1,853	1,189	60	9,878

Notes:

1 Corporate group FTEs are allocated to OPG's business units using the percentage of labour dollars allocated to each business. This results in the Corporate FTEs being allocated 80% to the nuclear facilities and 12% to the regulated hydroelectric facilities.

2 Consistent with the FTE allocation methodology in EB-2013-0321 and EB-2016-0152.

3 Non-Regular includes members from Electrical Power Systems Construction Association (EPSCA).

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Table 5
Continuity of Construction Work-In-Progress (CWIP) and In-Service Additions[1] ($M)
Year Ended December 31, 2019

Operating Group	CWIP Opening Balance[4] (a)	Capital Expenditures (b)	In-Service Additions[2] (c)	Retirements, Transfers & Adjustments (d)	CWIP Closing Balance (e)= a+b+c+d
Regulated Hydroelectric	177.1	204.2	(245.8)	0.8	136.3
Nuclear	4,855.6	1,482.5	(600.0)	(4.0)	5,734.1
Corporate Support Services[3]	27.6	34.9	(42.1)	0.0	20.4
Total	5,060.3	1,721.6	(887.9)	(3.2)	5,890.8

Notes:

1 All amounts include both fixed and intangible assets, as appropriate.

2 The amounts do not include other in-service additions of $62.9M for nuclear and $1.4M for regulated hydroelectric. The excluded other in-service additions include purchased minor fixed assets, capital spares and other amounts entering in-service assets directly rather than through CWIP.

3 The amounts do not include corporate support services fixed and intangible assets that are recovered via the Asset Service Fee.

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Table 6 Management's Discussion & Analysis (MD&A), Financial Statements, Nuclear Unit Capability Factors and Hydroelectric Availability		
Report	**Reporting Period**	**Particulars**
MD&A filed with the Ontario Securities Commission	Year Ended December 31, 2019	OPG's MD&A is filed with the Ontario Securities Commission and is posted on OPG's website at the following link: https://www.opg.com/document/2019-financial-results/
Financial Statements filed with the Ontario Securities Commission	Year Ended December 31, 2019	OPG's financial statements are filed with the Ontario Securities Commission and are posted on OPG's website at the following link: https://www.opg.com/document/2019-financial-results/
Nuclear Unit Capability Factors	Year Ended December 31, 2019	OPG's nuclear unit capability factors are provided on page 38 of OPG's MD&A, which is available at the following link: https://www.opg.com/document/2019-financial-results/
Availability for the Regulated Hydroelectric Facilities	Year Ended December 31, 2019	Availability for the regulated hydroelectric facilities is provided on page 39 of OPG's MD&A, which is available at the following link: https://www.opg.com/document/2019-financial-results/

Table 7: Pickering Performance Report

Metric	Actuals 2015	2016	2017	2018	2019	Metric	Annual Targets 2019	2020
Safety								
1-Year Total Recordable Injury Frequency (#/200k hours worked) [1]	0.44	0.49	0.06	0.16	0.11	Total Recordable Injury Frequency (#/200k hours worked)	0.20	TBD
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.05	0.04	0.05	0.05	0.02	Industrial Safety Accident Rate (#/200k hours worked)	0.10	TBD
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	97.72	97.23	83.96	81.65	70.32	Collective Radiation Exposure (Person-rem per unit)	92.30	TBD
1-Year Airborne Tritium Emissions (Curies) per Unit	2,409	3,067	3,103	2,772	2,517	Airborne Tritium Emissions (Curies) per Unit	2,500	TBD
Fuel Reliability Index (microcuries per gram) [4]	0.000421	0.000261	0.000584	0.000837	0.000187	Fuel Reliability Index (microcuries per gram)	0.000500	TBD
2-Year Reactor Trip Rate (# per 7,000 hours)	0.17	0.25	0.26	0.33	0.24	Reactor Trip Rate (# per 7,000 hours)	0.50	TBD
3-Year Auxiliary Feedwater System Unavailability (#)	0.0115	0.0070	0.0000	0.0039	0.0039	Auxiliary Feedwater System Unavailability (#)	0.0200	TBD
3-Year Emergency AC Power Unavailability (#)	0.0030	0.0030	0.0030	0.0000	0.0003	Emergency AC Power Unavailability (#)	0.0250	TBD
3-Year High Pressure Safety Injection Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.00013	High Pressure Safety Injection Unavailability (#)	0.0200	TBD
Reliability								
Rolling Average[2] WANO NPI (Index)	68.5	76.3	76.7	74.9	82.5	WANO NPI (Index)	74.3	TBD
Rolling Average[2] Forced Loss Rate (%)	6.85	3.76	5.01	5.20	3.39	Forced Loss Rate (%)	3.50	TBD
Rolling Average[2] Unit Capability Factor (%)	77.32	77.03	77.36	79.55	83.31	Unit Capability Factor (%)	80.56	TBD
Rolling Average[2] Chemistry Performance Indicator (Index)	1.06	1.04	1.02	1.02	1.02	Chemistry Performance Indicator (Index)	1.03	TBD
1-Year On-line Deficient Maintenance Backlog (work orders per unit)	251	350	383	279	114	On-line Deficient Maintenance Backlog (work orders per unit)	133	TBD
1-Year On-line Deficient Critical Maintenance Backlog (work orders per unit)			41	9	5	On-line Deficient Critical Maintenance Backlog (work orders per unit)	9	TBD
1-Year On-line Corrective Maintenance Backlog (work orders per unit)	125	116	25	17	9	On-line Corrective Maintenance Backlog (work orders per unit)	12	TBD
1-Year On-line Corrective Critical Maintenance Backlog (work orders per unit)			0	0	1	On-line Corrective Critical Maintenance Backlog (work orders per unit)	0	TBD
Value for Money								
3-Year Total Generating Cost per MWh ($ per Net MWh)	67.36	68.06	67.22	67.76	62.39	Total Generating Cost per MWh ($ per Net MWh)	64.89	TBD
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[5]			49.26	49.29	44.85	Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)	--	TBD
3-Year Total Generating Cost per Unit (M $ per Unit)	228.04	231.63	233.75	234.18	228.27	Total Generating Cost per Unit (M $ per Unit)	232.93	TBD
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[5]			184.69	183.77	176.31	Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)	--	TBD
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)	56.49	57.12	56.89	57.92	53.84	Non-Fuel Operating Cost per MWh ($ per Net MWh)	56.67	TBD
3-Year Fuel Cost per MWh ($ per Net MWh)	5.71	5.75	5.31	4.86	4.23	Fuel Cost per MWh ($ per Net MWh)	4.12	TBD
3-Year Capital Cost per MW DER (k$ per MW)	33.86	34.23	33.91	33.39	30.66	Capital Cost per MW DER (k$ per MW)	28.55	TBD
Human Performance								
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours) [3]	0.11000	0.03840	0.11600	0.14310	0.02000	18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)	0.08000	TBD

Notes
1. In 2018, Ontario Power Generation selected Total Recordable Injury Frequency (replacing All Injury Rate) as a measure for evaluating Health and Safety performance, and reflects a change instituted by the Canadian Electrical Association. Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked. Data prior to 2018 are All Injury Rate figures.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2015-2016 figures have been restated from 10k ISAR and contractor hours to 200k ISAR and contractor hours.
4. Indicates performance in the most recent quarter
5. 2017 - 2019 Normalized Actuals utilize normalization methodology for CANDU technology (including outage duration) and age-related impacts

Table 8 Darlington Performance Report

Metric	Actuals 2015	2016	2017	2018	2019	Metric	Annual Targets 2019	2020
Safety								
1-Year Total Recordable Injury Frequency (#/200k hours worked)[1]	0.22	0.23	0.40	0.32	0.00	Total Recordable Injury Frequency (#/200k hours worked)	0.20	TBD
Rolling Average[2] Industrial Safety Accident Rate (#/200k hours worked)	0.08	0.06	0.04	0.04	0.04	Industrial Safety Accident Rate (#/200k hours worked)	0.10	TBD
Rolling Average[2] Collective Radiation Exposure (Person-rem per unit)	79.55	68.77	91.80	85.43	83.23	Collective Radiation Exposure (Person-rem per unit)	80.00	TBD
1-Year Airborne Tritium Emissions (Curies) per Unit	1,313	846	875	982	1,213	Airborne Tritium Emissions (Curies) per Unit	900	TBD
Fuel Reliability Index (microcuries per gram)[4]	0.000122	0.000343	0.000179	0.000187	0.000295	Fuel Reliability Index (microcuries per gram)	0.000500	TBD
2-Year Reactor Trip Rate (# per 7,000 hours)	0.13	0.24	0.29	0.15	0.00	Reactor Trip Rate (# per 7,000 hours)	0.50	TBD
3-Year Auxiliary Feedwater System Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0000	Auxiliary Feedwater System Unavailability (#)	0.0200	TBD
3-Year Emergency AC Power Unavailability (#)	0.0000	0.0000	0.0000	0.0026	0.0026	Emergency AC Power Unavailability (#)	0.0250	TBD
3-Year High Pressure Safety Injection Unavailability (#)	0.0000	0.0000	0.0000	0.0000	0.0000	High Pressure Safety Injection Unavailability (#)	0.0200	TBD
Reliability								
Rolling Average[2] WANO NPI (Index)	83.7	87.8	82.0	90.7	88.9	WANO NPI (Index)	92.1	TBD
Rolling Average[2] Forced Loss Rate (%)	3.65	3.10	3.47	1.94	2.56	Forced Loss Rate (%)	1.00	TBD
Rolling Average[2] Unit Capability Factor (%)	83.96	86.16	82.17	86.89	87.06	Unit Capability Factor (%)	89.00	TBD
Rolling Average[2] Chemistry Performance Indicator (Index)	1.00	1.00	1.01	1.03	1.03	Chemistry Performance Indicator (Index)	1.10	TBD
1-Year On-line Deficient Maintenance Backlog (work orders per unit)	174	170	119	124	110	On-line Deficient Maintenance Backlog (work orders per unit)	115	TBD
1-Year On-line Deficient Critical Maintenance Backlog (work orders per unit)			15	9	3	On-line Deficient Critical Maintenance Backlog (work orders per unit)	6	TBD
1-Year On-line Corrective Maintenance Backlog (work orders per unit)	24	14	13	6	4	On-line Corrective Maintenance Backlog (work orders per unit)	4	TBD
1-Year On-line Corrective Critical Maintenance Backlog (work orders per unit)			1	0	0	On-line Corrective Critical Maintenance Backlog (work orders per unit)	0	TBD
Value for Money								
3-Year Total Generating Cost per MWh ($ per Net MWh)	44.38	45.63	54.40	59.06	67.00	Total Generating Cost per MWh ($ per Net MWh)	65.24	TBD
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[6]			37.94	37.65	38.84	Normalized Total Generating Cost per MWh ($ per Net MWh)[5]	53.61	TBD
3-Year Total Generating Cost per Unit (M $ per Unit)	282.37	292.49	337.56	384.74	442.14	Total Generating Cost per Unit (M $ per Unit)	433.95	TBD
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[6]			313.62	257.65	270.46	Normalized Total Generating Cost per Unit (M $ per Unit)[5]	356.60	TBD
3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)	33.19	33.00	39.62	42.14	47.08	Non-Fuel Operating Cost per MWh ($ per Net MWh)	45.30	TBD
Normalized 3-Year Non-Fuel Operating Cost per MWh ($ per Net MWh)[7]			36.89	36.37	37.84	Normalized Non-Fuel Operating Cost per MWh ($ per Net MWh)[5]	36.77	TBD
3-Year Fuel Cost per MWh ($ per Net MWh)	5.18	5.31	5.19	4.92	4.40	Fuel Cost per MWh ($ per Net MWh)	4.51	TBD
3-Year Capital Cost per MW DER (k$ per MW)	43.52	53.47	62.11	89.03	116.67	Capital Cost per MW DER (k$ per MW)	87.65	TBD
Normalized 3-Year Capital Cost per MW DER (k$ per MW)[7]			59.81	73.46	89.78	Normalized 3-Year Capital Cost per MW DER (k$ per MW)	--	TBD
Human Performance								
18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)[3]	0.06200	0.06940	0.05200	0.05100	0.03600	18-Month Human Performance Error Rate (# per 200k ISAR and contractor hours)	0.04000	TBD

Notes
1. In 2018, Ontario Power Generation selected Total Recordable Injury Frequency (replacing All Injury Rate) as a measure for evaluating Health and Safety performance, and reflects a change instituted by the Canadian Electrical Association. Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked. Data prior to 2018 are All Injury Rate figures.
2. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
3. 2015-2016 figures have been restated from 10k ISAR and contractor hours to 200k ISAR and contractor hours.
4. Indicates performance in the most recent quarter
5. 2019 Normalized Targets utilize the new ScottMadden methodology for refurbishment only.
6. 2017-2019 Normalized Actuals utilize both ScottMadden methdologies i.e. normalizing for refurbishment as well as CANDU technology (including outage duration) and age-related impacts
7. 2017-2019 Normalized Actuals utilize the new ScottMadden methdology for refubishment only

Table 9 OPG Nuclear Performance Report

Metric	Actuals				
	2015	2016	2017	2018	2019
Reliability					
Rolling Average[1] WANO NPI (Index)	74.6	80.9	78.5	80.1	84.6
Rolling Average[1] Unit Capability Factor (%)	80.00	80.70	78.96	82.00	84.56
Value for Money					
3-Year Total Generating Cost per MWh ($ per Net MWh)	54.58	55.57	60.53	63.31	64.58
Normalized 3-Year Total Generating Cost per MWh ($ per Net MWh)[3]			43.44	43.41	42.03
3-Year Total Generating Cost per Unit (M $ per Unit)	249.77	255.97	273.13	287.95	299.56
Normalized 3-Year Total Generating Cost per Unit (M $ per Unit)[3]			208.24	210.16	207.69

Metric	Annual Targets	
	2019	2020
WANO NPI (Index)	80.2	TBD
Unit Capability Factor (%)	84.47	TBD
Total Generating Cost per MWh ($ per Net MWh)	65.06	TBD
Normalized Total Generating Cost per MWh ($ per Net MWh)[2]	59.46	TBD
Total Generating Cost per Unit (M $ per Unit)	299.94	TBD
Normalized Total Generating Cost per Unit (M $ per Unit)[2]	274.15	TBD

Notes
1. Indicates a 2-Year Rolling Average for Pickering and a 3-Year Rolling Average for Darlington.
2. 2019 Normalized Targets utilize the new ScottMadden methodology for refurbishment only.
3. 2017-2019 Normalized Actuals utilize both ScottMadden methdologies i.e. normalizing for refurbishment as well as CANDU technology (including outage duration) and age-related impacts

Table 10
2019 Regulated Hydroelectric Performance Reporting

		Historical Actuals				2019		2020
Category	**Measure**	**2015**	**2016**	**2017**	**2018**	**Act**	**Tar**	**Tar**
Safety / Environment	**All Injury Rate (per 200k hours)[1]/ Total Recordable Injury Frequency**	0.84	1.27	2.05	1.68	1.32	1.21	TBD
	Environmental Performance Index (%)	115%	150%	145%	135%	150%	100%	TBD
Reliability	**Availability Factor (%)**	91.2%	89.0%	88.0%	86.0%	86.6%	88.0%	TBD
	Equivalent Forced Outage Rates (%)	1.8%	2.4%	3.3%	4.2%	6.4%	1.8%	TBD
Cost Effectiveness	**OM&A Unit Energy Cost ($/MWh)**	8.3	8.1	8.1	8.7	8.5	8.4	TBD
	3-Year Total Generating Cost ($/MWh)[2,3]	21.5	22.3	22.9	23.4	24.1	N/A	N/A

Notes:

1 In 2018, Ontario Power Generation selected Total Recordable Injury Frequency (replacing All Injury Rate) as a measure for evaluating Health and Safety performance, and reflects a change instituted by the Canadian Electrical Association. Total Recordable Injury Frequency is the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked.

2 2013 is the earliest year that OPG has provided Total Generating Cost for the regulated hydroelectric facilities. Accordingly, the 3-year average begins in 2015 with 2014 showing the 2-year average of the 2013 and 2014 results.

3 Per EB-2016-0152 Decision and Order P. 149-150 no target is filed for TGC.