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January 17, 2018

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2016-0152 – Ontario Power Generation Inc. Draft Order for Payment Amounts

Attached are a draft payment amounts order and supporting schedules for payment amounts for Ontario Power Generation's (OPG's) prescribed facilities.

The draft payment amounts order reflects the OEB's December 28, 2017 Decision and Order in the EB-2016-0152 proceeding (the "Decision"). The Decision approved an effective date of June 1, 2017 for the payment amounts.

OPG, on review of the Decision, identified that the OEB's direction relating to the calculation of interim revenue shortfall requires clarification as it does not appear to reflect the intent of the OEB. The directions in the Decision on implementation require OPG to determine forgone interim period revenue riders as part of its draft payment amounts order. The direction in this regard is as follows:

> With regard to the calculation of the **forgone revenue rider** for the period starting June 1, 2017 to the implementation date, the nuclear forgone revenue should be based on the monthly forecast production underpinning the application and approved by the OEB. The hydroelectric forgone revenue shall be based on pro-rating the 2015 actual regulated hydroelectric production. [Emphasis added] (Decision, p. 160)

The paragraph initially speaks to calculation of the foregone interim period revenue riders, but then refers to use of monthly forecast production (for nuclear facilities) and a pro-rating of the 2015 actual production (for the regulated hydroelectric facilities) in determining the foregone interim period revenue. OPG believes that the overall intent of the direction is to calculate an amount reflective of actual forgone interim period revenue that would have been earned in the period if payment amounts had been in place on the effective date of June 1, 2017, and that using actual production would in fact reflect this revenue. This approach is consistent with that established by the OEB in EB-2007-0905, the only other proceeding where such amounts were recoverable by OPG:

> The Decision, at pages 177-178, requires "that OPG remains at risk for its production forecast in the same way it would have been had the payments amounts been set on a prospective basis." To achieve the production risk exposure set out in its Decision, the Board directs that the new payment amounts be set using the forecast production for the test period and that **the interim period shortfall be calculated using the actual production during the interim period**… [Emphasis added] (EB-2007-0905, Payment Amounts Order, p. 3)

As such, in order to carry out the implementation directions provided in the Decision, OPG has calculated the foregone interim period revenue amounts using actual production for the period from the effective date of the 2017 payment amounts established in this proceeding to December 31, 2017 and a proxy production value for the period between January 1, 2018 and the implementation date of the payment amounts in 2018 (the derivation of these amounts are set out in Appendix F, Tables 1 and 2 accompanying the draft payment amounts order). The proxy production value reflects the nuclear production forecast for the corresponding months in 2018 as approved by the OEB and a pro-ration of the 2015 actual regulated hydroelectric production. OPG has then used forecast nuclear production approved in the Decision and the 2015 actual regulated hydroelectric production to divide the forgone interim period revenue calculated per above to determine interim period shortfall payment riders.

Consistent with the OEB's implementation of interim period shortfall riders in EB-2007-0905, the draft payment amounts order also provides for variance accounts to record the difference between the approved forgone interim period revenue and the amounts actually recovered over the collection period through production and riders. This approach keeps customers and OPG whole.

OPG has provided this draft payment amounts order in accordance with the OEB’s direction. OPG continues to review the Decision and provides this draft payment amounts order without prejudice to OPG's rights of rehearing, review, petition and appeal.

If you have any questions regarding this submission, please contact me at 416-592-2976.

Best regards,

[Original signed by]

Saba Zadeh

Attach.

cc: Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail
John Beauchamp (OPG) via e-mail
EB-2016-0152 Intervenors of Record via e-mail

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Christine Long
Presiding Member and Vice Chair

Cathy Spoel
Member

Ellen Fry
Member

DRAFT PAYMENT AMOUNTS ORDER

January 17, 2018

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board ("OEB") on May 27, 2016 (the "Application"). The Application was filed under section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act") seeking approval of the following payment amounts and payment riders:

- a payment amount for hydroelectric generating facilities ("regulated hydroelectric facilities") prescribed under *Ontario Regulation 53/05* of the Act, as amended, ("O. Reg. 53/05"), for the period from January 1, 2017 through December 31, 2017;
- a payment rider for the regulated hydroelectric facilities for the period from January 1, 2017 through December 31, 2018;
- a formula to be used to set payment amounts for the regulated hydroelectric facilities for the period from January 1, 2017 to December 31, 2021;

- payment amounts for nuclear generating facilities ("nuclear facilities") prescribed under O. Reg. 53/05, for the period from January 1, 2017 through December 31, 2021 ("IR Term"); and
- a payment rider for the nuclear facilities for the period from January 1, 2017 through December 31, 2018.

A full listing of approvals sought by OPG was filed as Ex. A1-2-2.

On December 8, 2016, the OEB issued an Interim Payment Amounts Order granting OPG's request to declare its current payment amounts interim effective January 1, 2017 for the regulated hydroelectric facilities and nuclear facilities.

A settlement conference was held and settlement was achieved on some issues. The OEB approved the settlement proposal on March 20, 2017. A copy of the OEB approved settlement proposal was attached as Schedule G to the Decision and Order (the "Decision").

The OEB issued the Decision on December 28, 2017. In the Decision, the OEB directed OPG to file a draft payment amounts order ("Draft Order"):

> … reflecting the payment amount setting determinations in this Decision for nuclear based on the parameters established for the five-year term, and for hydroelectric based on the 2017 and 2018 parameters… [including] the final revenue requirement and final production forecast for the nuclear facilities, and the final hydroelectric rate setting mechanism and 2017 and 2018 parameters, as reflected in the findings made by the OEB in this Decision. OPG shall include supporting schedules and a clear explanation of all the calculations and assumptions used in deriving the amounts used, and final unsmoothed payment amounts.

The OEB also directed OPG to file a "revised Revenue Requirement Work Form [("RRWF")] …that reflects both the application and the OEB Decision."

The OEB did not make a final determination on rate smoothing in the Decision. The OEB found that "a final decision regarding WAPA smoothing cannot be made until the outcomes of this Decision are reflected in unsmoothed hydroelectric and nuclear payment amounts and hydroelectric and nuclear payment amount riders." The OEB directed OPG to file a revised smoothing proposal in the Draft Order, reflecting the unsmoothed payment amounts resulting from the Decision and the requirements of O. Reg. 53/05. The OEB also ordered that the Draft

Order reflect three implementation date scenarios (March 1, 2018; April 1, 2018; and May 1, 2018).

The OEB ordered that an effective date of June 1, 2017 would apply for the new payment amounts for all of OPG's regulated facilities.

OPG filed a Draft Order on January 17, 2018, including a revised RRWF (filed as Appendix J). The Draft Order included a rate smoothing proposal based on the final unsmoothed payment amounts resulting from the Decision, which was filed as Appendix I. OPG proposed to defer recovery $732M of nuclear revenue requirement in total over the IR Term, which OPG estimated would produce a consistent $0.65 year-over-year impact on monthly residential customer bills during the IR Term (including the impact of payment riders to recover the revenue shortfall for the period between the approved effective date of June 1, 2017 and the implementation date of the new payment amounts). To mitigate bill impacts in 2018, OPG proposed that riders for recovery of the interim period revenue shortfall and approved deferral and variance account balances be implemented on January 1, 2019, for a three-year term ending on December 31, 2021.

THE BOARD ORDERS THAT:

1. Nuclear Revenue Requirement: The IR Term nuclear revenue requirements, net of stretch factor adjustments, are $2,973.0M in 2017, $3,032.4M in 2018, $3,116.5M in 2019, $3,579.1M in 2020, and $3,173.9M in 2021. These amounts are set out in Appendix A, Tables 1 to 5, col. (c) line 26. The nuclear revenue requirements include approved OM&A expenditures related to the Darlington Refurbishment Program ("DRP") of $41.5M in 2017, $13.8M in 2018, $3.5M in 2019, $48.4M in 2020, and $19.7M in 2021.

2. Nuclear Rate Base: The nuclear rate base is $3,418.4M in 2017, $3,439.4M in 2018, $3,358.7M in 2019, $7,319.0M in 2020, and $7,674.1M in 2021. These amounts are set out in Appendix A, Tables 1-5, col. (c), line 4. The nuclear rate base amounts include the following in-service additions specific to the Darlington Refurbishment Program: $4,800.2M related to Unit 2 in-service addition in 2020 and 2021; and $377.2M related to Unit Refurbishment Early In-service Projects, Safety Improvement Opportunities, and Facilities & Infrastructure Projects over the IR Term.

3. Nuclear Production Forecast ("NPF"): The production forecast for the nuclear facilities is 38.1 TWh in 2017, 38.5 TWh in 2018, 39.0 TWh in 2019, 37.4 TWh in 2020 and 35.4 TWh in 2021, as set out in Appendix C, Table 1, line 2.

4. Hydroelectric Payment Amounts ("HPA"): Commencing on the effective date of June 1, 2017 to December 31, 2017, the payment amount for the regulated hydroelectric facilities is $41.67/MWh (Appendix B, Table 1, col. (a), line 6). Effective January 1, 2018 to December 31, 2018, the payment amount for the regulated hydroelectric facilities is $42.05/MWh (Appendix B, Table 1, col. (b), line 6). For the periods January 1, 2019 to December 31, 2019, January 1, 2020 to December 31, 2020 and January 1, 2021 to December 31, 2021, the HPA amounts will be determined through an annual hydroelectric payment amount adjustment application. The HPA for each year shall be determined using the price-cap index proposed by OPG in Ex. A1-3-2 of this proceeding, under which the HPA for the prior year is adjusted by the generation industry-weighted inflation factor (using the most current Statistics Canada values for GDP-IPI (FDD) and Ontario AWE), less a productivity factor of 0% less a stretch factor of 0.3%.

   The hydroelectric incentive mechanism will continue to operate pursuant to the OEB's approval in EB-2013-0321. As also approved by the OEB in EB-2013-0321, the HPA will continue to apply to 50% of the output of OPG's Chats Falls Generating Station.

5. Nuclear Payment Amounts ("NPA"): The payment amounts for the nuclear facilities are $80.65MWh for the period from January 1, 2017 to December 31, 2017, and, effective January 1 of each year, $83.10/MWh in 2018, $76.17/MWh in 2019, $79.70/MWh in 2020, and $83.67/MWh in 2021, as set out in Appendix C, Table 1, line 3. These payment amounts reflect the rate smoothing proposal in Appendix I and the resulting nuclear rate smoothing deferral amounts approved below.

6. Nuclear Rate Smoothing Deferral Amounts: The nuclear deferral amounts to be recorded to the Rate Smoothing Deferral Account are $0 for January 1, 2017 to May 31, 2017, ($62M) for June 1, 2017 to December 31, 2017[1], ($165M) in 2018, $144M in 2019, $602M

[1] A $0 deferral amount applies for January 1, 2017 to May 31, 2017 as the previous, unsmoothed payment amount was in effect for production during that period. The June 1, 2017 to December 31, 2017 deferral

in 2020 and $213M in 2021, for a total of $732M of deferred revenue. The annual deferral amounts are set out in Appendix C, Table 1, line 5.

7. Recovery of Balances in Deferral and Variance Accounts: OPG shall recover the December 31, 2015 approved balances in the following deferral and variance accounts in accordance with Appendix D and Appendix E, effective January 1, 2019:

   - Hydroelectric Water Conditions Variance Account;
   - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
   - Hydroelectric Incentive Mechanism Variance Account;
   - Hydroelectric Surplus Baseload Generation Variance Account;
   - Income and Other Taxes Variance Account;
   - Capacity Refurbishment Variance Account;
   - Pension and OPEB Cost Variance Account
   - Pension & OPEB Cash Payment Variance Account;
   - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account;
   - Nuclear Liability Deferral Account;
   - Nuclear Development Variance Account;
   - Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts; and
   - Nuclear Deferral and Variance Over/Under Recovery Variance Account.

8. Continuing Deferral and Variance Accounts: OPG shall continue the following deferral and variance accounts in accordance with Appendix G, effective June 1, 2017:
   - Hydroelectric Water Conditions Variance Account;
   - Ancillary Services Net Revenue Variance Account;
   - Hydroelectric Incentive Mechanism Variance Account;
   - Hydroelectric Surplus Baseload Generation Variance Account;
   - Income and Other Taxes Variance Account;
   - Capacity Refurbishment Variance Account;
   - Pension and OPEB Cost Variance Account

amount of ($62M) is calculated using production weighting (on the NPF) that reflects the effective date of June 1, 2017 for the smoothed payment amounts established in this Order.

– Pension & OPEB Cash Versus Accrual Differential Deferral Account;
– Pension & OPEB Cash Payment Variance Account;
– Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account;
– Gross Revenue Charge Variance Account;
– Hydroelectric Deferral and Variance Over/Under Recovery Variance Account;
– Nuclear Liability Deferral Account;
– Nuclear Development Variance Account;
– Bruce Lease Net Revenues Variance Account;
– Nuclear Deferral and Variance Over/Under Recovery Variance Account; and
– Impact Resulting from Changes in Station End-of-life Dates (December 31, 2015) Deferral Account.

9. Hydroelectric Payment Rider ("HPR"): Effective January 1, 2019, the HPR for the recovery of the approved deferral and variance account balances for the regulated hydroelectric facilities (Hydroelectric Payment Rider A) is $0.96/MWh (Appendix D, Table 1, line 14). The approved disposition amount for this proceeding is a debit of $86.8M (Appendix D, Table 1, col (h), line 12) from hydroelectric deferral and variance accounts, reflecting recovery of audited December 31, 2015 balances in deferral and variance accounts (Appendix D, Table 1, col (a)) less amortization amounts approved in EB-2014-0370 (Appendix D, Table 1, col (b)). This payment rider is in effect until December 31, 2021. The HPR will apply to 50% of the output of OPG's Chats Falls Generating Station.

10. Nuclear Payment Rider ("NPR"): Effective January 1, 2019, the NPR for the recovery of the approved deferral and variance account balances for the nuclear facilities (Nuclear Payment Rider A) is $1.95/MWh (Appendix E, Table 1, line 18). The approved disposition amount for this proceeding is a debit of $217.9M (Appendix E, Table 1, col. (h), line 16) from nuclear deferral and variance accounts, reflecting recovery of audited December 31, 2015 balances in deferral and variance accounts (Appendix E, Table 1, col (a)), less amortization amounts approved in EB-2014-0370 (Appendix E, Table 1, col (b)). This payment rider is in effect until December 31, 2021.

11. Hydroelectric Interim Period Shortfall Recovery Payment Rider: The interim period revenue shortfall amount for the regulated hydroelectric facilities is determined as the difference between the annual HPA and the interim payment amounts for the period from

the effective date of the 2017 HPA to the implementation date of the 2018 HPA ("Hydroelectric Shortfall"). The approved Hydroelectric Shortfall for recovery is $21.1M (Appendix F, Table 1, line 10, cols. (a) plus (b)) reflecting the approved effective date of June 1, 2017, an implementation date of March 1, 2018, actual 2017 hydroelectric production from the effective date to December 31, 2017 and pro-ration of the 2015 actual regulated production for production after January 1, 2018. Effective January 1, 2019, to recover the Hydroelectric Shortfall, the interim period shortfall recovery payment rider for the regulated hydroelectric facilities is $0.23/MWh (Hydroelectric Payment Rider B) (Appendix F, Table 1, col. (b), line 12). This payment rider is in effect until December 31, 2021. Hydroelectric Payment Rider B will to apply to 50% of the output of OPG's Chats Falls Generating Station.

12. <u>Nuclear Interim Period Shortfall Recovery Payment Rider</u>: The interim period revenue shortfall amount for the nuclear facilities is determined as the difference between the annual NPA and the interim payment amount for the period from the effective date of the 2017 NPA to the implementation date of the 2018 NPA ("Nuclear Shortfall"). The approved Nuclear Shortfall for recovery is $700.6M (Appendix F, Table 2, line 5, cols. (a) plus (b)) reflecting the approved effective date of June 1, 2017, an implementation date of March 1, 2018, actual 2017 production from the effective date to December 31, 2017 and the approved 2018 NPF from January 1, 2018 to the implementation date. Effective January 1, 2019, to recover the Nuclear Shortfall, the interim period shortfall recovery payment rider for the nuclear facilities is $6.27/MWh (Nuclear Payment Rider B) (Appendix F, Table 2, col. (b), line 7). This payment rider is in effect until December 31, 2021.

13. <u>New Deferral and Variance Accounts:</u> OPG shall establish the following new deferral and variance accounts in accordance with the accounting orders in Appendix H. These accounts are effective June 1, 2017, unless otherwise noted:
    - Rate Smoothing Deferral Account (effective January 1, 2017);
    - Fitness for Duty Deferral Account;
    - SR&ED ITC Variance Account;
    - Hydroelectric Interim Period Shortfall (Hydroelectric Payment Rider B) Over/Under Recovery Variance Account; and
    - Nuclear Interim Period Shortfall (Nuclear Payment Rider B) Over/Under Recovery Variance Account.

14. The IESO shall make payments to OPG in accordance with this order as of March 1, 2018.

15. OPG shall file an accounting order application with the OEB and provide notice to intervenors of record in EB-2016-0152 if:
    i. OPG proposes an accounting change impacting the calculation of its nuclear liabilities, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, which results in a material revenue requirement impact for the prescribed facilities; or
    ii. OPG proposes to change the end-of-life dates of its prescribed nuclear facilities for depreciation and amortization purposes that results in a material non-asset retirement cost revenue requirement impact.

    An accounting order application shall only be required if the revenue requirement impact is neither reflected in current or proposed payment amounts nor recorded in an authorized deferral or variance account and the annualized revenue requirement impact for the prescribed facilities is $10M or greater.

DATED at Toronto _________________, 2018

ONTARIO ENERGY BOARD

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Kirsten Walli
Board Secretary

EB-2016-0152 PAYMENT AMOUNTS ORDER – APPENDICES

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APPENDIX A: REVENUE REQUIREMENT

Numbers may not add due to rounding.

Table 1
2017 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	2,916.4	(209.5)	2,706.9
2	**Working Capital**		700.5	0.0	700.5
3	**Cash Working Capital**		11.0	0.0	11.0
4	**Total Rate Base**		3,627.9	(209.5)	3,418.4
	Capitalization				
5	**Short-term Debt**	3	10.9	(0.5)	10.4
6	**Long-Term Debt**	3	1,572.1	19.8	1,591.9
7	**Common Equity**	3	1,520.9	(209.9)	1,311.0
8	**Adjustment for Lesser of UNL or ARC**	4	524.0	(18.9)	505.1
9	**Total Capital**		3,627.9	(209.5)	3,418.4
	Cost of Capital				
10	**Short-term Debt**	3	0.9	(0.0)	0.8
11	**Long-Term Debt**	3	76.8	1.0	77.8
12	**Return on Equity**	3	133.5	(18.4)	115.1
13	**Adjustment for Lesser of UNL or ARC**	4a	25.9	(0.9)	25.0
14	**Total Cost of Capital**		237.1	(18.4)	218.7
	Expenses:				
15	**OM&A**	5	2,343.9	(101.6)	2,242.2
16	**Fuel**	6	214.9	(9.8)	205.2
17	**Depreciation & Amortization**	7	367.0	(23.8)	343.2
18	**Property Tax**		14.6	0.0	14.6
19	**Total Expenses**		2,940.4	(135.2)	2,805.2
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	8	(16.9)	11.6	(5.3)
21	**Ancillary and Other Revenue**		37.8	0.0	37.8
22	**Total Other Revenues**		20.9	11.6	32.5
23	**Income Tax**	9	(7.3)	(11.1)	(18.4)
24	**Revenue Requirement Before Stretch Factor**		3,149.4	(176.4)	2,973.0
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	10	0.0	0.0	0.0
26	**Revenue Requirement Net of Stretch Factor**		3,149.4	(176.4)	2,973.0
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	11	108.9	(108.9)	0.0
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,258.3	(285.3)	2,973.0

For notes see Table 1a.

Table 1a
Notes to Table 1
2017 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (a).

2 Updated as follows to reflect OEB Decision and Order (P. 17 for update to Ex. J21.1 forecast; P. 21 for reduction in Auxiliary Heating System in-service amount; P. 22 for reduction in Operations Support Building in-service amount; P. 19 for 10% reduction in forecast nuclear operations and corporate support in-service additions). Calculated as:

	Description	2017
(a)	OPG Proposed Net Fixed Assets (line 1, col. (a))	$ 2,916.4
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (f), line 12 less J21.1 Att. 1, Table 1, col. (f), line 12)	$ (134.4)
(c)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (f), line 13 less J21.1 Att. 1, Table 1, col. (f), line 13)	$ (18.9)
(d)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 9, line 5, co. (f) less PAO App. A, Table 10, line 5, col. (f))	$ (25.3)
(e)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 9, line 6, col. (f) less PAO App. A, Table 10, line 6, col. (f))	$ (6.1)
(f)	Subtotal (a) + (b) + (c) + (d) + (e)	$ 2,731.7
(g)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 9, col. (f), line 7 less PAO App. A, Table 10, col. (e), line 7)	$ (24.8)
(h)	OEB Approved Net Fixed Assets (f) + (g)	$ 2,706.9

Supporting continuity schedules for OEB Approved Net Fixed Assets are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the OEB's Decision and Order (P. 100) to approve a capital structure of 45% Equity : 55% Debt. See PAO App. A, Table 11 for supporting details.

4 Per OEB Decision and Order P. 98, adjusted to reflect the impacts of the final 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next asset retirement obligation adjustment (per Ex. J21.1, Att. 2, Table 3, line 13, col. (f)).
(PAO App. A, Table 9, line 9, col. (f) less PAO App. A, Table 10, line 9, col. (f)).

4a Per PAO App. A, Table 11, line 7, col. (d).

5 Updated to reflect the OEB's disallowances from Base OM&A (OEB Decision and Order P. 55), corporate allocated costs (OEB Decision and Order P. 72), compensation (OEB Decision and Order P. 84), Fitness for Duty (Ex. N1-1-1, Chart 2, Line 5) which will be tracked in the Fitness for Duty Variance Account (OEB Decision and Order P. 57), and low and intermediate level waste management variable expenses associated with Ex. J21.2. Calculated as:

	Description	2017
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,343.9
(b)	Low and intermediate level waste management variable expenses: Update to Nuclear Liabilities to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98)	$ (1.2)
(c)	Base OM&A Disallowance (OEB Decision and Order P. 55)	$ (25.0)
(d)	Corporate Allocated Costs Disallowance (OEB Decision and Order P. 72)	$ (45.0)
(e)	Compensation Disallowance (OEB Decision and Order P. 84)	$ (30.0)
(f)	Removal of Fitness for Duty costs (Ex. N1-1-1, Chart 2, Line 5) to be tracked in separate deferral account (OEB's Decision and Order P. 57)	$ (0.5)
(g)	OEB Approved OM&A expenses (a) + (b) + (c) + (d) + (e) + (f)	$ 2,242.2

6 Adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

7 Per PAO App. A, Table 10, col. (b), line 10. Calculated as:

	Description	2017
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 367.0
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 8 + line 10 + line 11 less J21.1 Att. 1, Table 5, col. (b) + (c), line 8 + line 10 + line 11)	$ (19.0)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 5, col. (b))	$ (0.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 6, col. (b))	$ (0.2)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 347.0
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 7)	$ (0.7)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 13 less J21.1 Att. 1, Table 5, col. (b), line 13)	$ (3.1)
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 343.2

8 Adjustment represents update to Nuclear Liabilities to reflect final 2017 ONFA contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate, per Ex. J21.2, Att. 1, Table 1, line 30 (OEB Decision and Order P. 93).

9 Updated to reflect the impacts of the OEB Decision and Order as outlined above per PAO App. A, Table 16.

10 Updated to increase the nuclear stretch factor to 0.6% (OEB Decision and Order P. 139), to expand the scope of the stretch factor to include the revenue requirement impact associated with the nuclear operations and support services in-service capital additions in each year from 2017 - 2021 (starting in 2018), and to include base, outage, project and allocated corporate OM&A expenses (OEB Decision and Order P. 141). Supporting calculation is provided in PAO App. A, Table 7.

11 Proposed amortization of deferral and variance account over the two year period 2017 to 2018 is removed. Deferral and variance accounts will be amortized in 2019 through 2021, spread equally over the three years (PAO App. E, Table 1, cols. (e)-(h), line 16).

Table 2

2018 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	2,909.2	(167.5)	2,741.7
2	**Working Capital**		686.7	0.0	686.7
3	**Cash Working Capital**		11.0	0.0	11.0
4	**Total Rate Base**		3,606.9	(167.5)	3,439.4
	Capitalization				
5	**Short-term Debt**	3	11.0	(0.4)	10.6
6	**Long-Term Debt**	3	1,600.7	43.3	1,644.0
7	**Common Equity**	3	1,548.5	(194.7)	1,353.8
8	**Adjustment for Lesser of UNL or ARC**	4	446.7	(15.7)	431.0
9	**Total Capital**		3,606.9	(167.5)	3,439.4
	Cost of Capital				
10	**Short-term Debt**	3	1.0	(0.0)	1.0
11	**Long-Term Debt**	3	73.6	2.0	75.6
12	**Return on Equity**	3	136.0	(17.1)	118.9
13	**Adjustment for Lesser of UNL or ARC**	4a	22.1	(0.8)	21.3
14	**Total Cost of Capital**		232.7	(15.9)	216.8
	Expenses:				
15	**OM&A**	5	2,349.3	(101.4)	2,248.0
16	**Fuel**	6	216.8	(9.9)	207.0
17	**Depreciation & Amortization**	7	395.0	(2.6)	392.4
18	**Property Tax**		14.9	0.0	14.9
19	**Total Expenses**		2,976.1	(113.8)	2,862.3
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	8	(17.1)	9.9	(7.3)
21	**Ancillary and Other Revenue**		23.3	0.0	23.3
22	**Total Other Revenues**		6.2	9.9	16.0
23	**Income Tax**	9	(18.4)	0.0	(18.4)
24	**Revenue Requirement Before Stretch Factor**		3,184.3	(139.6)	3,044.6
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	10	5.0	7.3	12.3
26	**Revenue Requirement Net of Stretch Factor**		3,179.3	(146.9)	3,032.4
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	11	108.9	(108.9)	0.0
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,288.2	(255.8)	3,032.4

For notes see Table 2a.

Table 2a
Notes to Table 2
2018 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (b).

2 Updated as follows to reflect OEB Decision and Order (P. 17 for update to Ex. J21.1 forecast; P. 21 for reduction in Auxiliary Heating System in-service amount; P. 22 for reduction in Operations Support Building in-service amount; P. 19 for 10% reduction in forecast nuclear operations and corporate support in-service additions). Calculated as:

	Description	2018
(a)	OPG Proposed Net Fixed Assets (line 1, col. (a))	$ 2,909.2
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (i), line 12 less J21.1 Att. 1, Table 1, col. (i), line 12)	$ (51.4)
(c)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (i), line 13 less J21.1 Att. 1, Table 1, col. (i), line 13)	$ (15.7)
(d)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 9, line 15, col. (f) less PAO App. A, Table 10, line 15, col. (f))	$ (25.9)
(e)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 9, line 16, col. (f) less PAO App. A, Table 10, line 16, col. (f))	$ (7.3)
(f)	Subtotal (a) + (b) + (c) + (d) + (e)	$ 2,808.9
(g)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 9, col. (f), line 17 less PAO App. A, Table 10, col. (e), line 17)	$ (67.2)
(h)	OEB Approved Net Fixed Assets (f) + (g)	$ 2,741.7

Supporting continuity schedules for OEB Approved Net Fixed Assets are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the OEB's Decision and Order (P. 100) to approve a capital structure of 45% Equity : 55% Debt. See PAO App. A, Table 12 for supporting details.

4 Per OEB Decision and Order P. 98, adjusted to reflect the impacts of the final 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next asset retirement obligation adjustment (per Ex. J21.1, Att. 2, Table 3, line 13, col. (i)).
(PAO App. A, Table 9, Line 19, col. (f) less PAO App. A, Table 10, line 19, col. (f))

4a Per PAO App. A Table 12, line 7, col. (d).

5 Updated to reflect the OEB's disallowances from Base OM&A (OEB Decision and Order P. 55), corporate allocated costs (OEB Decision and Order P. 72), compensation (OEB Decision and Order P. 84), Fitness for Duty (Ex. N1-1-1, Chart 2, Line 5) which will be tracked in the Fitness for Duty Variance Account (OEB Decision and Order P. 57), and low and intermediate level waste management variable expenses associated with Ex. J21.2. Calculated as:

	Description	2018
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,349.3
(b)	Low and intermediate level waste management variable expenses: Update to Nuclear Liabilities to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98)	$ (0.9)
(c)	Base OM&A Disallowance (OEB Decision and Order P. 55)	$ (25.0)
(d)	Corporate Allocated Costs Disallowance (OEB Decision and Order P. 72)	$ (45.0)
(e)	Compensation Disallowance (OEB Decision and Order P. 84)	$ (30.0)
(f)	Removal of Fitness for Duty costs (Ex. N1-1-1, Chart 2, Line 5) to be tracked in separate deferral account (OEB's Decision and Order P. 57)	$ (0.5)
(g)	OEB Approved OM&A expense (a) + (b) + (c) + (d) + (e) + (f)	$ 2,248.0

6 Adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

7 Per PAO App. A, Table 10, Col (b), line 20. Calculated as:

	Description	2018
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 395.0
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 15 + line 17 + line 18 less J21.1 Att. 1, Table 5, col. (b) + (c), line 15 + line 17 + line 18)	$ 3.5
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 15, col. (b))	$ (0.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 16, col. (b))	$ (0.2)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 397.5
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 17)	$ (2.0)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 20 less J21.1 Att. 1, Table 5, col. (b), line 20)	$ (3.1)
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 392.4

8 Adjustment represents update to Nuclear Liabilities to reflect final 2017 ONFA contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate, per Ex. J21.2, Att. 1, Table 1, line 30 (OEB Decision and Order P. 93).

9 Updated to reflect the impacts of the OEB Decision and Order as outlined above per PAO App. A, Table 17.

10 Updated to increase the nuclear stretch factor to 0.6% (OEB Decision and Order P. 139), to expand the scope of the stretch factor to include the revenue requirement impact associated with the nuclear operations and support services in-service capital additions in each year from 2017 - 2021 (starting in 2018), and to include base, outage, project and allocated corporate OM&A expenses (OEB Decision and Order P. 141). Supporting calculation is provided in PAO App. A, Table 7.

11 Proposed amortization of deferral and variance account over the two year period 2017 to 2018 is removed. Deferral and variance accounts will be amortized in 2019 through 2021, spread equally over the three years (PAO App. E, Table 1, cols. (e)-(h), line 16).

Table 3

2019 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	2,804.8	(117.5)	2,687.2
2	**Working Capital**		660.5	0.0	660.5
3	**Cash Working Capital**		11.0	0.0	11.0
4	**Total Rate Base**		3,476.2	(117.5)	3,358.7
	Capitalization				
5	**Short-term Debt**	3	10.9	(0.3)	10.6
6	**Long-Term Debt**	3	1,573.6	66.8	1,640.4
7	**Common Equity**	3	1,522.3	(171.5)	1,350.8
8	**Adjustment for Lesser of UNL or ARC**	4	369.4	(12.6)	356.8
9	**Total Capital**		3,476.2	(117.5)	3,358.7
	Cost of Capital				
10	**Short-term Debt**	3	1.1	(0.0)	1.1
11	**Long-Term Debt**	3	71.2	3.0	74.2
12	**Return on Equity**	3	133.7	(15.1)	118.6
13	**Adjustment for Lesser of UNL or ARC**	4a	18.3	(0.6)	17.7
14	**Total Cost of Capital**		224.2	(12.7)	211.5
	Expenses:				
15	**OM&A**	5	2,423.1	(117.7)	2,305.4
16	**Fuel**	6	229.1	(12.0)	217.1
17	**Depreciation & Amortization**	7	400.3	13.8	414.0
18	**Property Tax**		15.3	0.0	15.3
19	**Total Expenses**		3,067.8	(116.0)	2,951.8
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	8	(27.4)	6.8	(20.6)
21	**Ancillary and Other Revenue**		24.2	0.0	24.2
22	**Total Other Revenues**		(3.2)	6.8	3.6
23	**Income Tax**	9	(18.4)	0.0	(18.4)
24	**Revenue Requirement Before Stretch Factor**		3,276.8	(135.5)	3,141.3
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	10	10.1	14.7	24.8
26	**Revenue Requirement Net of Stretch Factor**		3,266.7	(150.2)	3,116.5
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	11	0.0	72.6	72.6
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,266.7	(77.6)	3,189.1

For notes see Table 3a.

Table 3a
Notes to Table 3
2019 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (c).

2 Updated as follows to reflect OEB Decision and Order (P. 17 for update to Ex. J21.1 forecast; P. 21 for reduction in Auxiliary Heating System in-service amount; P. 22 for reduction in Operations Support Building in-service amount; P. 19 for 10% reduction in forecast nuclear operations and corporate support in-service additions). Calculated as:

	Description	2019
(a)	OPG Proposed Net Fixed Assets (line 1, col. (a))	$ 2,804.8
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (c), line 19 less J21.1 Att. 1, Table 1, col. (c), line 19)	$ 30.1
(c)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (c), line 20 less J21.1 Att. 1, Table 1, col. (c), line 20)	$ (12.7)
(d)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 9, line 25, col. (f) less PAO App. A, Table 10, line 25, col. (f))	$ (25.1)
(e)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 9, line 26, col. (f) less PAO App. A, Table 10, line 26, col. (f))	$ (7.0)
(f)	Subtotal (a) + (b) + (c) + (d) + (e)	$ 2,790.0
(g)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 9, col. (f), line 27 less PAO App. A, Table 10, col. (e), line 27)	$ (102.9)
(h)	OEB Approved Net Fixed Assets (f) + (g)	$ 2,687.2

Supporting continuity schedules for OEB Approved Net Fixed Assets are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the OEB's Decision and Order (P. 100) to approve a capital structure of 45% Equity : 55% Debt. See PAO App. A, Table 13 for supporting details.

4 Per OEB Decision and Order P. 98, adjusted to reflect the impacts of the final 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next asset retirement obligation adjustment (per Ex. J21.1, Att. 2, Table 3, line 20, col. (c)).
(PAO App. A, Table 9, line 29, col. (f) less PAO App. A, Table 10, line 29, col. (f)).

4a Per App. A PAO Table 13, line 7, col. (d).

5 Updated to reflect the OEB's disallowances from Base OM&A (OEB Decision and Order P. 55), corporate allocated costs (OEB Decision and Order P. 72), compensation (OEB Decision and Order P. 84), Fitness for Duty (Ex. N1-1-1, Chart 2, Line 5) which will be tracked in the Fitness for Duty Variance Account (OEB Decision and Order P. 57), and low and intermediate level waste management variable expenses associated with Ex. J21.2. Calculated as:

	Description	2019
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,423.1
(b)	Low and intermediate level waste management variable expenses: Update to Nuclear Liabilities to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98)	$ (1.0)
(c)	Base OM&A Disallowance (OEB Decision and Order P. 55)	$ (25.0)
(d)	Corporate Allocated Costs Disallowance (OEB Decision and Order P. 72)	$ (45.0)
(e)	Compensation Disallowance (OEB Decision and Order P. 84)	$ (30.0)
(f)	Removal of Fitness for Duty costs (Ex. N1-1-1, Chart 2, Line 5) to be tracked in separate deferral account (OEB's Decision and Order P. 57)	$ (16.7)
(g)	OEB Approved OM&A (a) + (b) + (c) + (d) + (e) + (f)	$ 2,305.4

6 Adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

7 Per PAO App. A, Table 10, Col (b), line 30. Calculated as:

	Description	2019
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 400.3
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 22 + line 24 + line 25 less J21.1 Att. 1, Table 5, col. (b) + (c), line 22 + line 24 + line 25)	$ 21.1
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 25, col. (b))	$ (0.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 26, col. (b))	$ (0.2)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 420.3
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 27)	$ (3.1)
(g)	Adjustment for Ex. J21.1 - Asset Reitrement Costs (J21.1 Att. 2, Table 7, col. (b), line 27 less J21.1 Att. 1, Table 5, col. (b), line 27)	$ (3.1)
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 414.0

8 Adjustment represents update to Nuclear Liabilities to reflect final 2017 ONFA contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate, per Ex. J21.2, Att. 1, Table 1, line 30 (OEB Decision and Order P. 93).

9 Updated to reflect the impacts of the OEB Decision and Order as outlined above per PAO App. A, Table 18.

10 Updated to increase the nuclear stretch factor to 0.6% (OEB Decision and Order P. 139), to expand the scope of the stretch factor to include the revenue requirement impact associated with the nuclear operations and support services in-service capital additions in each year from 2017 - 2021 (starting in 2018), and to include base, outage, project and allocated corporate OM&A expenses (OEB Decision and Order P. 141). Supporting calculation is provided in PAO App. A, Table 7.

11 Proposed amortization of deferral and variance account over the two year period 2017 to 2018 is removed. Deferral and variance accounts will be amortized in 2019 through 2021, spread equally over the three years (PAO App. E, Table 1, cols. (e)-(h), line 16).

Table 4

2020 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	6,805.2	(134.8)	6,670.3
2	**Working Capital**		637.7	0.0	637.7
3	**Cash Working Capital**		11.0	0.0	11.0
4	**Total Rate Base**		7,453.8	(134.8)	7,319.0
	Capitalization				
5	**Short-term Debt**	3	18.0	(0.2)	17.8
6	**Long-Term Debt**	3	3,634.5	217.7	3,852.2
7	**Common Equity**	3	3,509.2	(342.9)	3,166.4
8	**Adjustment for Lesser of UNL or ARC**	4	292.2	(9.5)	282.7
9	**Total Capital**		7,453.8	(134.8)	7,319.0
	Cost of Capital				
10	**Short-term Debt**	3	1.9	(0.0)	1.8
11	**Long-Term Debt**	3	163.3	9.8	173.1
12	**Return on Equity**	3	308.1	(30.1)	278.0
13	**Adjustment for Lesser of UNL or ARC**	4a	14.5	(0.5)	14.0
14	**Total Cost of Capital**		487.7	(20.8)	466.9
	Expenses:				
15	**OM&A**	5	2,467.0	(112.8)	2,354.2
16	**Fuel**	6	221.1	(9.2)	211.9
17	**Depreciation & Amortization**	7	541.2	49.2	590.3
18	**Property Tax**		15.7	0.0	15.7
19	**Total Expenses**		3,245.0	(72.9)	3,172.1
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	8	(23.8)	3.7	(20.1)
21	**Ancillary and Other Revenue**		23.8	0.0	23.8
22	**Total Other Revenues**		(0.0)	3.7	3.7
23	**Income Tax**	9	59.2	(77.6)	(18.4)
24	**Revenue Requirement Before Stretch Factor**		3,791.9	(174.9)	3,616.9
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	10	15.3	22.5	37.8
26	**Revenue Requirement Net of Stretch Factor**		3,776.6	(197.5)	3,579.1
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	11	0.0	72.6	72.6
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,776.6	(124.8)	3,651.7

For notes see Table 4a.

Table 4a
Notes to Table 4
2020 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (d).

2 Updated as follows to reflect OEB Decision and Order (P. 17 for update to Ex. J21.1 forecast; P. 21 for reduction in Auxiliary Heating System in-service amount; P. 22 for reduction in Operations Support Building in-service amount; P. 19 for 10% reduction in forecast nuclear operations and corporate support in-service additions). Calculated as:

	Description	2020
(a)	OPG Proposed Net Fixed Assets (line 1, col. (a))	$ 6,805.2
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (f), line 19 less J21.1 Att. 1, Table 1, col. (f), line 19)	$ 37.3
(c)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (f), line 20 less J21.1 Att. 1, Table 1, col. (f), line 20)	$ (9.5)
(d)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 9, line 35, col. (f) less PAO App. A, Table 10, line 35, col. (f))	$ (24.3)
(e)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 9, line 36, col. (f) less PAO App. A, Table 10, line 36, col. (f))	$ (6.8)
(f)	Subtotal (a) + (b) + (c) + (d) + (e)	$ 6,801.8
(g)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 9, col. (f), line 37 less PAO App. A, Table 10, col. (e), line 37)	$ (131.4)
(h)	OEB Approved Net Fixed Assets (f) + (g)	$ 6,670.3

Supporting continuity schedules for OEB Approved Net Fixed Assets are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the OEB's Decision and Order (P. 100) to approve a capital structure of 45% Equity : 55% Debt. See PAO App. A, Table 14 for supporting details.

4 Per OEB Decision and Order P. 98, adjusted to reflect the impacts of the final 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next asset retirement obligation adjustment (per Ex. J21.1, Att. 2, Table 3, line 20, col. (f)).
(PAO App. A, Table 9, line 39, col. (f) less PAO App. A, Table 10, line 39, col. (f)).

4a Per PAO App. A Table 14, line 7, col. (d).

5 Updated to reflect the OEB's disallowances from Base OM&A (OEB Decision and Order P. 55), corporate allocated costs (OEB Decision and Order P. 72), compensation (OEB Decision and Order P. 84), Fitness for Duty (Ex. N1-1-1, Chart 2, Line 5) which will be tracked in the Fitness for Duty Variance Account (OEB Decision and Order P. 57), and low and intermediate level waste management variable expenses associated with Ex. J21.2. Calculated as:

	Description	2020
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,467.0
(b)	Low and intermediate level waste management variable expenses: Update to Nuclear Liabilities to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98)	$ (1.1)
(c)	Base OM&A Disallowance (OEB Decision and Order P. 55)	$ (25.0)
(d)	Corporate Allocated Costs Disallowance (OEB Decision and Order P. 72)	$ (45.0)
(e)	Compensation Disallowance (OEB Decision and Order P. 84)	$ (30.0)
(f)	Removal of Fitness for Duty costs (Ex. N1-1-1, Chart 2, Line 5) to be tracked in separate deferral account (OEB's Decision and Order P. 57)	$ (11.7)
(g)	OEB Approved OM&A (a) + (b) + (c) + (d) + (e) + (f)	$ 2,354.2

6 Adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

7 Per PAO App. A, Table 10, col. (b), line 40. Calculated as:

	Description	2020
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 541.2
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 29 + line 31 + line 32 less J21.1 Att. 1, Table 5, col. (b) + (c), line 29 + line 31 + line 32)	$ 57.5
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 35, col. (b))	$ (0.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 36, col. (b))	$ (0.2)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 597.6
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 37)	$ (4.1)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 34 less J21.1 Att. 1, Table 5, col. (b), line 34)	$ (3.1)
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 590.3

8 Adjustment represents update to Nuclear Liabilities to reflect final 2017 ONFA contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate, per Ex. J21.2, Att. 1, Table 1, line 30 (OEB Decision and Order P. 93).

9 Updated to reflect the impacts of the OEB Decision and Order as outlined above per PAO App. A, Table 19.

10 Updated to increase the nuclear stretch factor to 0.6% (OEB Decision and Order P. 139), to expand the scope of the stretch factor to include the revenue requirement impact associated with the nuclear operations and support services in-service capital additions in each year from 2017 - 2021 (starting in 2018), and to include base, outage, project and allocated corporate OM&A expenses (OEB Decision and Order P. 141). Supporting calculation is provided in PAO App. A, Table 7.

11 Proposed amortization of deferral and variance account over the two year period 2017 to 2018 is removed. Deferral and variance accounts will be amortized in 2019 through 2021, spread equally over the three years (PAO App. E, Table 1, cols. (e)-(h), line 16).

Table 5

2021 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Rate Base				
1	**Net Fixed Assets**	2	7,252.5	(212.9)	7,039.6
2	**Working Capital**		623.5	0.0	623.5
3	**Cash Working Capital**		11.0	0.0	11.0
4	**Total Rate Base**		7,887.0	(212.9)	7,674.1
	Capitalization				
5	**Short-term Debt**	3	18.5	(0.2)	18.3
6	**Long-Term Debt**	3	3,876.6	214.3	4,090.9
7	**Common Equity**	3	3,742.3	(380.3)	3,362.0
8	**Adjustment for Lesser of UNL or ARC**	4	249.6	(46.7)	202.9
9	**Total Capital**		7,887.0	(212.9)	7,674.1
	Cost of Capital				
10	**Short-term Debt**	3	1.9	(0.0)	1.9
11	**Long-Term Debt**	3	173.7	9.6	183.3
12	**Return on Equity**	3	328.6	(33.4)	295.2
13	**Adjustment for Lesser of UNL or ARC**	4a	12.4	(2.3)	10.0
14	**Total Cost of Capital**		516.5	(26.1)	490.3
	Expenses:				
15	**OM&A**	5	2,347.6	(112.9)	2,234.6
16	**Fuel**	6	205.9	(9.1)	196.8
17	**Depreciation & Amortization**	7	316.7	(28.3)	288.3
18	**Property Tax**		17.0	0.0	17.0
19	**Total Expenses**		2,887.1	(150.3)	2,736.8
	Less:				
	Other Revenues				
20	**Bruce Lease Revenues Net of Direct Costs**	8	(38.1)	(2.4)	(40.4)
21	**Ancillary and Other Revenue**		24.6	0.0	24.6
22	**Total Other Revenues**		(13.4)	(2.4)	(15.8)
23	**Income Tax**	9	(5.0)	(13.4)	(18.4)
24	**Revenue Requirement Before Stretch Factor**		3,412.0	(187.5)	3,224.6
	(line 14 + line 19 - line 22 + line 23)				
25	**Cumulative Nuclear Stretch Dollars**	10	20.6	30.1	50.6
26	**Revenue Requirement Net of Stretch Factor**		3,391.4	(217.5)	3,173.9
	(line 24 - line 25)				
27	**Amortization of Deferral & Variance Account Amounts**	11	0.0	72.6	72.6
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,391.4	(144.9)	3,246.5

For notes see Table 5a.

Numbers may not add due to rounding.

Table 5a
Notes to Table 5
2021 Summary of Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per PAO App. A, Table 6, col. (e).

2 Updated as follows to reflect OEB Decision and Order (P. 17 for update to Ex. J21.1 forecast; P. 21 for reduction in Auxiliary Heating System in-service amount; P. 22 for reduction in Operations Support Building in-service amount; P. 19 for 10% reduction in forecast nuclear operations and corporate support in-service additions). Calculated as:

	Description	2021
(a)	OPG Proposed Net Fixed Assets (line 1, col. (a))	$ 7,252.5
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (i), line 19 less J21.1 Att. 1, Table 1, col. (i), line 19)	$ (26.4)
(c)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 3, col. (i), line 20 less J21.1 Att. 1, Table 1, col. (i), line 20)	$ (7.8)
(d)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 9, line 45, col. (f) less PAO App. A, Table 10, line 45, col. (f))	$ (23.5)
(e)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 9, line 46, col. (f) less PAO App. A, Table 10, line 46, col. (f))	$ (6.6)
(f)	Subtotal (a) + (b) + (c) + (d) + (e)	$ 7,188.2
(g)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 9, col. (f), line 47 less PAO App. A, Table 10, col. (e), line 47)	$ (148.6)
(h)	OEB Approved Net Fixed Assets (f) + (g)	$ 7,039.6

Supporting continuity schedules for OEB Approved Net Fixed Assets are provided in PAO App. A, Tables 9 and 10.

3 Updated to reflect the OEB's Decision and Order (P. 100) to approve a capital structure of 45% Equity : 55% Debt. See PAO App. A, Table 15 for supporting details.

4 Per OEB Decision and Order P. 98, adjusted to reflect the impacts of the final 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next asset retirement obligation adjustment. The balance in Table 5, line 8, col. (c) is equal to the average unfunded nuclear liability balance of $202.9M underlying Ex. J21.2.

4a Per PAO App. A, Table 15, line 7, col. (d).

5 Updated to reflect the OEB's disallowances from Base OM&A (OEB Decision and Order P. 55), corporate allocated costs (OEB Decision and Order P. 72), compensation (OEB Decision and Order P. 84), Fitness for Duty (Ex. N1-1-1, Chart 2, Line 5) which will be tracked in the Fitness for Duty Variance Account (OEB Decision and Order P. 57), and low and intermediate level waste management variable expenses associated with Ex. J21.2. Calculated as:

	Description	2021
(a)	OPG Proposed OM&A expenses (line 15, col. (a))	$ 2,347.6
(b)	Low and intermediate level waste management variable expenses: Update to Nuclear Liabilities to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98)	$ (1.2)
(c)	Base OM&A Disallowance (OEB Decision and Order P. 55)	$ (25.0)
(d)	Corporate Allocated Costs Disallowance (OEB Decision and Order P. 72)	$ (45.0)
(e)	Compensation Disallowance (OEB Decision and Order P. 84)	$ (30.0)
(f)	Removal of Fitness for Duty costs (Ex. N1-1-1, Chart 2, Line 5) to be tracked in separate deferral account (OEB's Decision and Order P. 57)	$ (11.7)
(g)	OEB Approved OM&A (a) + (b) + (c) + (d) + (e) + (f)	$ 2,234.6

6 Adjustments to used fuel storage and disposal variable expenses to reflect actual year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

7 Per PAO App. A, Table 10, col. (b), line 50. Calculated as:

	Description	2021
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 316.7
(b)	Adjustment for Ex. J21.1 - Excluding Asset retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 36 + line 38 + line 39 less J21.1 Att. 1, Table 5, col. (b) + (c), line 36 + line 38 + line 39)	$ (22.2)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 45, col. (b))	$ (0.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 46, col. (b))	$ (0.2)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 293.4
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 47)	$ (4.8)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 41 less J21.1 Att. 1, Table 5, col. (b), line 41)	$ (0.2)
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 288.3

8 Adjustment represents update to Nuclear Liabilities to reflect final 2017 ONFA contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate, per Ex. J21.2, Att. 1, Table 1, line 30 (OEB Decision and Order P. 93).

9 Updated to reflect the impacts of the OEB Decision and Order as outlined above per PAO App. A, Table 20.

10 Updated to increase the nuclear stretch factor to 0.6% (OEB Decision and Order P. 139), to expand the scope of the stretch factor to include the revenue requirement impact associated with the nuclear operations and support services in-service capital additions in each year from 2017 - 2021 (starting in 2018), and to include base, outage, project and allocated corporate OM&A expenses (OEB Decision and Order P. 141). Supporting calculation is provided in PAO App. A, Table 7.

11 Proposed amortization of deferral and variance account over the two year period 2017 to 2018 is removed. Deferral and variance accounts will be amortized in 2019 through 2021, spread equally over the three years (PAO App. E, Table 1, cols. (e)-(h), line 16).

Table 6

2017 to 2021 Summary of Proposed Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
			Note 1	Note 1	Note 1	Note 1	Note 1
	Rate Base						
1	**Net Fixed Assets**		2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
2	**Working Capital**		700.5	686.7	660.5	637.7	623.5
3	**Cash Working Capital**		11.0	11.0	11.0	11.0	11.0
4	**Total Rate Base**		3,627.9	3,606.9	3,476.2	7,453.8	7,887.0
	Capitalization						
5	**Short-term Debt**		10.9	11.0	10.9	18.0	18.5
6	**Long-Term Debt**		1,572.1	1,600.7	1,573.6	3,634.5	3,876.6
7	**Common Equity**		1,520.9	1,548.5	1,522.3	3,509.2	3,742.3
8	**Adjustment for Lesser of UNL or ARC**		524.0	446.7	369.4	292.2	249.6
9	**Total Capital**		3,627.9	3,606.9	3,476.2	7,453.8	7,887.0
	Cost of Capital						
10	**Short-term Debt**		0.9	1.0	1.1	1.9	1.9
11	**Long-Term Debt**		76.8	73.6	71.2	163.3	173.7
12	**Return on Equity**		133.5	136.0	133.7	308.1	328.6
13	**Adjustment for Lesser of UNL or ARC**		25.9	22.1	18.3	14.5	12.4
14	**Total Cost of Capital**		237.1	232.7	224.2	487.7	516.5
	Expenses:						
15	**OM&A**	2	2,343.9	2,349.3	2,423.1	2,467.0	2,347.6
16	**Fuel**	3	214.9	216.8	229.1	221.1	205.9
17	**Depreciation & Amortization**		367.0	395.0	400.3	541.2	316.7
18	**Property Tax**		14.6	14.9	15.3	15.7	17.0
19	**Total Expenses**		2,940.4	2,976.1	3,067.8	3,245.0	2,887.1
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**		(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
21	**Ancillary and Other Revenue**	4	37.8	23.3	24.2	23.8	24.6
22	**Total Other Revenues**		20.9	6.2	(3.2)	(0.0)	(13.4)
23	**Income Tax**	5	(7.3)	(18.4)	(18.4)	59.2	(5.0)
24	**Revenue Requirement Before Stretch Factor**		3,149.4	3,184.3	3,276.8	3,791.9	3,412.0
	(line 14 + line 19 - line 22 + line 23)						
25	**Cumulative Nuclear Stretch Dollars**		0.0	5.0	10.1	15.3	20.6
26	**Revenue Requirement Net of Stretch Factor**		3,149.4	3,179.3	3,266.7	3,776.6	3,391.4
	(line 24 - line 25)						
27	**Amortization of Deferral & Variance Account Amounts**		108.9	108.9	0.0	0.0	0.0
28	**Revenue Requirement Net of Stretch Factor Plus Deferral & Variance Account Amounts** (line 26 + line 27)		3,258.3	3,288.2	3,266.7	3,776.6	3,391.4

For notes see Table 6a.

Table 6a
Notes to Table 6
2017 to 2021 Summary of Proposed Nuclear Revenue Requirement and Deferral Account Amortization Amounts ($M)

1 Per Ex. N2-1-1, Table 1 unless otherwise noted.
2 Reduced from Ex. N2-1-1, Table 1, line 15 by $2.1M in 2017, $2.0M in 2018, $2.0M in 2019, $2.1M in 2020 and $1.6M in 2021 to reflect adjustments identified in Ex. L-6.6-1, Staff-139 (a); includes labour and non-labour costs.
3 Reduced from Ex. N2-1-1, Table 1, line 16 by line (f) below, to reflect a 2% downward adjustment to the nuclear fuel bundle unit cost per Ex. O-1-1, P. 9 (OEB-approved Settlement Agreement, Issue 6.3):

	Description	**2017**	**2018**	**2019**	**2020**	**2021**
(a)	Original Proposed Fuel Bundle Unit Cost ($/MWh) (Ex. F2-5-1, Table 1, line 4)	4.27	4.22	4.15	4.48	4.28
(b)	Settlement Agreement Fuel Bundle Unit Cost ($/MWh) (Ex. O1-1-1, P. 9)	4.18	4.14	4.07	4.39	4.19
(c)	Forecast Production (TWh) (PAO App. C, Table 1, line 2)	38.1	38.5	39.0	37.4	35.4
(d)	Original Proposed Fuel Bundle Cost ($ million) (a) * (c)	162.6	162.3	161.9	167.3	151.4
(e)	Adjusted Proposed Fuel Bundle Cost ($ million) (b) * (c)	159.3	159.3	158.8	164.0	148.3
(f)	Total Fuel Bundle Cost Reduction ($ million) (e) - (d)	(3.3)	(3.1)	(3.0)	(3.3)	(3.2)

4 Per Ex. N2-1-1, Table 1, line 21, adjusted to reflect an increase in the 50% share of the net revenue forecast for heavy water sales per Ex. O1-1-1, Page 11 (OEB-approved Settlement Agreement, Issue 7.1). Increases to these forecast revenues (at 100%) are $6.1M in 2017, $1.3M in 2018, $1.5M in 2019, $1.6M in 2020, and $1.7M in 2021.
5 As calculated in PAO App. A, Table 21, line 26.

Table 7
Calculation of Nuclear Stretch Factor
January 1, 2017 to December 31, 2021 ($M)

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	Stretch Factor Applicable Nuclear OM&A Expenses						
1	Total OEB Approved Nuclear OM&A Expenses	1		2,248.0	2,305.4	2,354.2	2,234.6
2	Less: Darlington Refurbishment OM&A Expenses	2		(13.8)	(3.5)	(48.4)	(19.7)
3	Less: Pickering Extended Operations Enabling Costs	3		(55.3)	(107.1)	(104.3)	-
4	Less: Other Excluded Costs	4		(165.6)	(191.6)	(196.2)	(182.5)
5	Total OM&A Expenses Subject to Stretch Factor (line 1 + line 2 + line 3 + line 4)		-	2,013.4	2,003.1	2,005.3	2,032.4
	Stretch Factor Applicable Nuclear Capital In-Service Additions Revenue Requirement						
6	Cost of Capital for Nuclear Capital In-Service Additions	6		10.2	29.8	43.2	50.7
7	Depreciation Expense	5		21.4	56.7	104.6	50.7
8	Income Tax Expense	7		0.2	2.4	15.9	(1.9)
9	Total Nuclear Capital In-Service Additions Revenue Requirement Subject to Stretch Factor (line 6 + line 7 + line 8)			31.8	89.0	163.6	99.5
10	Total Revenue Requirement Amount Subject to Stretch Factor (line 5 + line 9)			2,045.2	2,092.1	2,168.9	2,131.9
11	Nuclear Stretch Factor (OEB Decision and Order P. 139)			0.6%	0.6%	0.6%	0.6%
12	**Nuclear Stretch Factor Revenue Requirement Adjustment ($M)** (line 10 x line 11) + Prior Year			**12.3**	**24.8**	**37.8**	**50.6**

Notes:
1 PAO App. A, Table 1 to 5, line 15, col. (c).
2 Ex. F2-1-1, Table 1, line 5.
3 Ex. F2-2-3, Chart 2, line 7.
4 Calculated as Ex. F2-1-1, Table 1: line 6 + line 8 + line 9, plus Ex. N1-1-1 Chart 2, line 1.
5 The continuinty of OEB-approved nuclear operations and support services in-service capital additions for 2018-2021 and resulting rate base amounts are as follows:

		2018	2019	2020	2021
(a)	Opening Balance: Non-DRP In-service Fixed Assets (Prior year (d))	-	313.6	610.6	730.4
(b)	In-Service Additions Excluding Darlington Refurbishment (PAO App. A, Table 9 col. (b))	334.9	353.7	224.4	166.3
(c)	Depreciation Expense on In-Service Additions	(21.4)	(56.7)	(104.6)	(50.7)
(d)	Closing Balance: In-service Fixed Assets Excluding Darlington Refurbishment (a) + (b) + (c)	313.6	610.6	730.4	846.0
(e)	Net Fixed Assets Rate Base Amount = [(a) + (d)] / 2	156.8	462.1	670.5	788.2

6 Cost of capital for OEB-approved nuclear operations and support services in-service capital additions for 2018-2021 is calculated as follows:

		2018	2019	2020	2021
(a)	Net Fixed Asset Rate Base (Note 5, line (e))	156.8	462.1	670.5	788.2
(b)	Return on Equity (45% Equity at 8.78% per PAO App. A, Tables 12-15)	6.2	18.3	26.5	31.1
(c)	Cost of Debt (55% Debt at Total Debt Cost per PAO, App. A, Tables 12-15)	4.0	11.6	16.7	19.5
(d)	Total Cost of Capital (b) + (c)	10.2	29.8	43.2	50.7

7 Income tax expense associated with the OEB-approved nuclear operations and support services in-service capital additions for 2018-2021 is calculated as follows:

		2018	2019	2020	2021
(a)	Depreciation Expense (Note 5, line (c))	(21.4)	(56.7)	(104.6)	(50.7)
(b)	Capital Cost Allowance	(26.9)	(67.6)	(83.5)	(87.7)
(c)	Return on Equity (Note 6, line (b))	6.2	18.3	26.5	31.1
(d)	Net Regulatory Taxable Income Increase / (Decrease) (Note 6 line (b) less Note 5 line (c) plus Note 7 line (b))	0.7	7.3	47.6	(5.8)
(e)	Income Tax Expense (line (d) x 25% / (1 - 25%)	0.2	2.4	15.9	(1.9)

Table 8
Summary of Approved Revenue Deficiency - Nuclear
January 1, 2017 to December 31, 2021

Line No.	Description	Note	Nuclear 2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
1	**Forecast Production (TWh)**	1	38.1	38.5	39.0	37.4	35.4
2	**Approved Payment Amount from EB-2013-0321 ($/MWh)**	2	59.29	59.29	59.29	59.29	59.29
3	**Indicated Production Revenue ($M)** (line 1 x line 2)		2,258.9	2,280.9	2,313.9	2,214.8	2,097.9
4	**Revenue Requirement ($M)**	3	2,973.0	3,032.4	3,116.5	3,579.1	3,173.9
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)		714.1	751.4	802.6	1,364.3	1,076.0

Notes:
1 Approved production forecast per OEB Decision and Order P. 12.
2 EB-2013-0321 Payment Amounts Order, Appendix D, Table 1, line 3.
3 PAO App. A, Tables 1-5, line 26, col. (c).

Numbers may not add due to rounding.

Table 9
Continuity of Approved Property, Plant and Equipment - Nuclear ($M)[1]
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Note	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
			(a)	(b)	(c)	(d)	(e)	(f)
			Note 1					
	2017:							
	Per Ex. J21.1, Att. 2 Update:							
1	**Darlington NGS**		1,245.8	279.2	0.0	279.2	1,524.9	1,385.3
2	**Darlington Refurbishment Program**		645.2	8.5	0.0	8.5	653.7	649.4
3	**Pickering NGS**		2,260.6	212.8	0.0	212.8	2,473.4	2,367.0
4	**Nuclear Support Divisions**		390.1	16.8	0.0	16.8	406.9	398.5
	OEB Adjustments:							
5	**Auxiliary Heating System Disallowance**	2	(24.7)	(2.8)	0.0	(2.8)	(27.5)	(26.1)
6	**Operations Support Building Disallowance**	2	(5.0)	(2.7)	0.0	(2.7)	(7.8)	(6.4)
7	**Forecast In-Service Additions Reduction**	3	0.0	(50.3)	0.0	(50.3)	(50.3)	(25.2)
8	**Nuclear - Excluding Asset Retirement Costs**		4,511.8	461.4	0.0	461.4	4,973.3	4,742.5
9	**Asset Retirement Costs (Ex. J21.1, Att 2)**		2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
10	**Total**		6,675.1	461.4	0.0	461.4	7,136.6	6,905.8
	2018:							
	Per Ex. J21.1, Att. 2 Update:							
11	**Darlington NGS**		1,524.9	263.2	0.0	263.2	1,788.2	1,656.5
12	**Darlington Refurbishment Program**		653.7	8.9	0.0	8.9	662.5	658.1
13	**Pickering NGS**		2,473.4	98.4	0.0	98.4	2,571.7	2,522.5
14	**Nuclear Support Divisions**		406.9	10.5	0.0	10.5	417.5	412.2
	OEB Adjustments:							
15	**Auxiliary Heating System Disallowance**	2	(27.5)	0.0	0.0	0.0	(27.5)	(27.5)
16	**Operations Support Building Disallowance**	2	(7.8)	0.0	0.0	0.0	(7.8)	(7.8)
17	**Forecast In-Service Additions Reduction**	3	(50.3)	(37.2)	0.0	(37.2)	(87.5)	(68.9)
18	**Nuclear - Excluding Asset Retirement Costs**		4,973.3	343.8	0.0	343.8	5,317.1	5,145.2
19	**Asset Retirement Costs (Ex. J21.1, Att 2)**		2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
20	**Total**		7,136.6	343.8	0.0	343.8	7,480.4	7,308.5
	2019:							
	Per Ex. J21.1, Att. 2 Update:							
21	**Darlington NGS**		1,788.2	351.8	0.0	351.8	2,139.9	1,964.0
22	**Darlington Refurbishment Program**		662.5	0.0	0.0	0.0	662.5	662.5
23	**Pickering NGS**		2,571.7	31.8	0.0	31.8	2,603.5	2,587.6
24	**Nuclear Support Divisions**		417.5	9.5	0.0	9.5	426.9	422.2
	OEB Adjustments:					0.0	0.0	0.0
25	**Auxiliary Heating System Disallowance**	2	(27.5)	0.0	0.0	0.0	(27.5)	(27.5)
26	**Operations Support Building Disallowance**	2	(7.8)	0.0	0.0	0.0	(7.8)	(7.8)
27	**Forecast In-Service Additions Reduction**	3	(87.5)	(39.3)	0.0	(39.3)	(126.8)	(107.2)
28	**Nuclear - Excluding Asset Retirement Costs**		5,317.1	353.7	0.0	353.7	5,670.8	5,493.9
29	**Asset Retirement Costs (Ex. J21.1, Att 2)**		2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
30	**Total**		7,480.4	353.7	0.0	353.7	7,834.1	7,657.2
	2020:							
	Per Ex. J21.1, Att. 2 Update:							
31	**Darlington NGS**		2,139.9	201.5	0.0	201.5	2,341.4	2,240.7
32	**Darlington Refurbishment Program**	4	662.5	4,809.2	0.0	4,809.2	5,471.8	4,858.8
33	**Pickering NGS**		2,603.5	38.3	0.0	38.3	2,641.8	2,622.7
34	**Nuclear Support Divisions**		426.9	9.6	0.0	9.6	436.5	431.7
	OEB Adjustments:							
35	**Auxiliary Heating System Disallowance**	2	(27.5)	0.0	0.0	0.0	(27.5)	(27.5)
36	**Operations Support Building Disallowance**	2	(7.8)	0.0	0.0	0.0	(7.8)	(7.8)
37	**Forecast In-Service Additions Reduction**	3	(126.8)	(24.9)	0.0	(24.9)	(151.8)	(139.3)
38	**Nuclear - Excluding Asset Retirement Costs**		5,670.8	5,033.7	0.0	5,033.7	10,704.5	9,979.3
39	**Asset Retirement Costs (Ex. J21.1, Att 2)**		2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
40	**Total**		7,834.1	5,033.7	0.0	5,033.7	12,867.8	12,142.6
	2021:							
	Per Ex. J21.1, Att. 2 Update:							
41	**Darlington NGS**		2,341.4	143.7	0.0	143.7	2,485.1	2,413.2
42	**Darlington Refurbishment Program**		5,471.8	0.4	0.0	0.4	5,472.2	5,472.0
43	**Pickering NGS**		2,641.8	31.4	0.0	31.4	2,673.2	2,657.5
44	**Nuclear Support Divisions**		436.5	9.7	0.0	9.7	446.3	441.4
	OEB Adjustments:							
45	**Auxiliary Heating System Disallowance**	2	(27.5)	0.0	0.0	0.0	(27.5)	(27.5)
46	**Operations Support Building Disallowance**	2	(7.8)	0.0	0.0	0.0	(7.8)	(7.8)
47	**Forecast In-Service Additions Reduction**	3	(151.8)	(18.5)	0.0	(18.5)	(170.3)	(161.0)
48	**Nuclear - Excluding Asset Retirement Costs**		10,704.5	166.8	0.0	166.8	10,871.2	10,787.9
49	**Asset Retirement Costs (Ex. J21.1, Att 2)**		2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
50	**Total**		12,867.8	166.8	0.0	166.8	13,034.6	12,951.2

For notes see Table 9a.

Table 9a
Notes to Table 9
Continuity of Approved Property, Plant and Equipment - Nuclear ($M)

Notes:

1 Lines 1-4, 9, 11-14, 19, 21-24, 29, 31-34, 39, 41-44, 49 per Ex. J21.1 Att. 2, Table 5 (OEB's Decision and Order P. 17).

2 Per OEB Decision and Order P. 21 and P. 22 OPG is to apply a disallowance for Auxiliary Heating System (AHS) project and for Operations Support Building (OSB) project, calculated as 50% of the difference between actual or forecast in-service and in-service identified in First Execution BCS. Detailed calculation is as follows:

	$M	Actual or forecast in-service (JT 2.16)	In-Service-First Execution BCS *	Disallowance
		(a)	(b)	[(a) - (b)] x 50%
(a)	Project 25619 DN OSB	60.6	45.1	7.8
(b)	Project 34000 DN AHS	98.7	43.6	27.6
	Total (a) + (b)	159.3	88.7	35.3

* First Execution BCS total capital in-service amount for OSB is per EB 2013-0321, JT 3.5, Att. A. First Execution BCS total capital in-service amount for AHS is per EB 2013-0321 Ex. D2-2-1, Attachment 8-5, p. A-1. The difference between these amounts and the total project cost provided in JT 2.16 represents non-capital removal costs incurred as part of the projects.

Operations Support Building Disallowance: Of the $60.6M proposed in-service amount, $55.1M was placed into service in 2015 (Ex. L-4.4-1, Staff 76) and $5.5M was forecasted to be placed into service in 2017. The $7.8M disallowance is applied to reduce the 2017 forecast in-service amount by 50% x $5.5M or $2.7M and the 2017 gross plant opening balance by the remaining $5.0M (numbers don't add due to rounding).

Auxiliary Heating System Disallowance: Of the $98.7M proposed in-service amount, $93.1M was placed into service in 2016 and $5.6M was forecasted to be placed into service in 2017. The $27.6M disallowance is applied to reduce the 2017 forecast in-service amount by $5.6M x 50% or $2.8M and the 2017 gross plant opening balance by the remaining $24.7M (numbers don't add due to rounding).

3 The 10% reduction to the nuclear operations and support services forecast in-service capital additions (OEB's Decision and Order P. 18) is calculated as 10% of the sum of in-service additions in col. (b), excluding Darlington Refurbishment Program and Asset Retirement Costs.

4 Reflects in-service addition of $4,777.7M for the return to service of the refurbished Darlington Unit 2 in mid February 2020. This amount is assigned a ten and a half-month weighting in calculating the 2020 Gross Plant Rate Base amount.

Table 10
Continuity of Approved Accumulated Depreciation and Amortization - Nuclear ($M)[1]
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Note	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(b1)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation and Amortization Rate Base Amount
			(a)	(b)	(c)	(d)	(e)
	2017:						
	Per Ex. J21.1, Att. 2 Update:						
1	**Darlington NGS**		414.5	44.2	0.0	458.7	436.6
2	**Darlington Refurbishment Program**		28.1	18.9	0.0	47.0	37.6
3	**Pickering NGS**		1,645.6	182.0	0.0	1,827.7	1,736.7
4	**Nuclear Support Divisions**		318.6	25.6	0.0	344.2	331.4
	OEB Adjustments:						
5	**Auxiliary Heating System Disallowance**	2	(0.5)	(0.8)	0.0	(1.3)	(0.9)
6	**Operations Support Building Disallowance**	2	(0.1)	(0.2)	0.0	(0.4)	(0.3)
7	**Forecast In-Service Additions Reduction**	3	0.0	(0.7)	0.0	(0.7)	(0.4)
8	**Nuclear - Excluding Asset Retirement Costs**		2,406.2	269.1	0.0	2,675.3	2,540.8
9	**Asset Retirement Costs**		1,621.1	74.1	0.0	1,695.3	1,658.2
10	**Total**		4,027.3	343.2	0.0	4,370.6	4,199.0
	2018:						
	Per Ex. J21.1, Att. 2 Update:						
11	**Darlington NGS**		458.7	51.9	0.0	510.6	484.7
12	**Darlington Refurbishment Program**		47.0	19.2	0.0	66.2	56.6
13	**Pickering NGS**		1,827.7	227.7	0.0	2,055.4	1,941.6
14	**Nuclear Support Divisions**		344.2	22.5	0.0	366.7	355.5
	OEB Adjustments:						
15	**Auxiliary Heating System Disallowance**	2	(1.3)	(0.8)	0.0	(2.0)	(1.7)
16	**Operations Support Building Disallowance**	2	(0.4)	(0.2)	0.0	(0.6)	(0.5)
17	**Forecast In-Service Additions Reduction**	3	(0.7)	(2.0)	0.0	(2.7)	(1.7)
18	**Nuclear - Excluding Asset Retirement Costs**		2,675.3	318.3	0.0	2,993.6	2,834.4
19	**Asset Retirement Costs**		1,695.3	74.1	0.0	1,769.4	1,732.3
20	**Total**		4,370.6	392.4	0.0	4,763.0	4,566.8
	2019:						
	Per Ex. J21.1, Att. 2 Update:						
21	**Darlington NGS**		510.6	59.3	0.0	569.9	540.2
22	**Darlington Refurbishment Program**		66.2	19.3	0.0	85.6	75.9
23	**Pickering NGS**		2,055.4	246.2	0.0	2,301.6	2,178.5
24	**Nuclear Support Divisions**		366.7	19.3	0.0	385.9	376.3
	OEB Adjustments:						
25	**Auxiliary Heating System Disallowance**	2	(2.0)	(0.8)	0.0	(2.8)	(2.4)
26	**Operations Support Building Disallowance**	2	(0.6)	(0.2)	0.0	(0.8)	(0.7)
27	**Forecast In-Service Additions Reduction**	3	(2.7)	(3.1)	0.0	(5.9)	(4.3)
28	**Nuclear - Excluding Asset Retirement Costs**		2,993.6	339.9	0.0	3,333.5	3,163.5
29	**Asset Retirement Costs**		1,769.4	74.1	0.0	1,843.5	1,806.5
30	**Total**		4,763.0	414.0	0.0	5,177.0	4,970.0
	2020:						
	Per Ex. J21.1, Att. 2 Update:						
31	**Darlington NGS**		569.9	66.7	0.0	636.6	603.2
32	**Darlington Refurbishment Program**		85.6	148.4	0.0	234.0	159.8
33	**Pickering NGS**		2,301.6	287.7	0.0	2,589.3	2,445.5
34	**Nuclear Support Divisions**		385.9	18.5	0.0	404.5	395.2
	OEB Adjustments:						
35	**Auxiliary Heating System Disallowance**	2	(2.8)	(0.8)	0.0	(3.6)	(3.2)
36	**Operations Support Building Disallowance**	2	(0.8)	(0.2)	0.0	(1.0)	(0.9)
37	**Forecast In-Service Additions Reduction**	3	(5.9)	(4.1)	0.0	(10.0)	(7.9)
38	**Nuclear - Excluding Asset Retirement Costs**		3,333.5	516.2	0.0	3,849.7	3,591.6
39	**Asset Retirement Costs**		1,843.5	74.1	0.0	1,917.7	1,880.6
40	**Total**		5,177.0	590.3	0.0	5,767.4	5,472.2
	2021:						
	Per Ex. J21.1, Att. 2 Update:						
41	**Darlington NGS**		636.6	71.3	0.0	707.8	672.2
42	**Darlington Refurbishment Program**		234.0	166.9	0.0	400.9	317.5
43	**Pickering NGS**		2,589.3	31.5	0.0	2,620.8	2,605.1
44	**Nuclear Support Divisions**		404.5	16.8	0.0	421.3	412.9
	OEB Adjustments:						
45	**Auxiliary Heating System Disallowance**	2	(3.6)	(0.8)	0.0	(4.4)	(4.0)
46	**Operations Support Building Disallowance**	2	(1.0)	(0.2)	0.0	(1.3)	(1.2)
47	**Forecast In-Service Additions Reduction**	3	(10.0)	(4.8)	0.0	(14.8)	(12.4)
48	**Nuclear - Excluding Asset Retirement Costs**		3,849.7	280.7	0.0	4,130.4	3,990.1
49	**Asset Retirement Costs**		1,917.7	7.7	0.0	1,925.4	1,921.5
50	**Total**		5,767.4	288.3	0.0	6,055.7	5,911.6

For notes see Table 10a.

Table 10a
Notes to Table 10
Continuity of Approved Accumulated Depreciation and Amortization - Nuclear ($M)

Notes:

1 Lines 1-4, 9, 11-14, 19, 21-24, 29, 31-34, 39, 41-44, 49 per Ex. J21.1 Att. 2, Table 5 (OEB's Decision and Order P. 17).

2 Depreciation impact of Auxiliary Heating System (AHS) and Operations Support Building (OSB) capital in-service disallowances detailed at App. A, Table 9a, Note 2 is calculated using the estimated remaining service life of the Darlington station to December 31, 2052.

		2017	2018	2019	2020	2021
(a)	Project 25619 DN OSB (Accumulated Depreciation)	0.3	0.5	0.7	0.9	1.2
(b)	Project 34000 DN AHS (Accumulated Depreciation)	0.9	1.7	2.4	3.2	4.0
(c)	Total (a) + (b)	1.1	2.1	3.1	4.2	5.2

3 Represents depreciation impact of the 10% reduction in nuclear operations and support services forecast capital in-service additions at App. A, Table 10, lines 7, 17, 27, 37 and 47. Consistent with the fact that the forecast increase in the nuclear operations capital program relative to historical periods cited in the OEB's finding of the disallowance (OEB's Decision and Order P. 17) relates to the Darlington station, the depreciation impact of the disallowance is calculated using the estimated remaining service life of the Darlington station to December 31, 2052.

Table 11
Capitalization and Cost of Capital
Summary of Approved Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2017

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	10.4	0.4%	1.41%	0.8
2	**Existing/Planned Long-Term Debt**	1, 2	807.0	27.7%	4.89%	39.4
3	**Other Long-Term Debt Provision**	1	784.9	26.9%	4.89%	38.3
4	**Total Debt**	3	1,602.3	55.0%	4.91%	78.6
5	**Common Equity**	3	1,311.0	45.0%	8.78%	115.1
6	**Rate Base Financed by Capital Structure**		2,913.3	85.2%	6.65%	193.7
7	**Adjustment for Lesser of UNL or ARC**	4	505.1	14.8%	4.95%	25.0
8	**Rate Base**	5	3,418.4	100%	6.40%	218.7

Notes:

1 Long- and short-term debt cost rates as proposed by OPG were approved by the OEB (Ex. O1-1-1 P. 8).

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 5, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6 and Ex. L-03.1-20 VECC-005, Table 5, line 1.

3 The OEB approved a Debt / Equity ratio of 55% debt, 45% equity (OEB Decision and Order P. 100) and a 8.78% return on common equity (OEB Decision and Order P. 111).

4 Col. (a) is per PAO App. A, Table 9, line 9, col. (f) less PAO App. A, Table 10, line 9, col. (f).
Col. (c) reflects update to Nuclear Liabilities for actual 2017-2021 ONFA contribution schedule, year-end 2016 asset retirement obligation adjustment, and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

5 Col. (a) is per Table 1, line 4, col. (c).

Table 12
Capitalization and Cost of Capital
Summary of Approved Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2018

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	10.6	0.4%	2.73%	1.0
2	**Existing/Planned Long-Term Debt**	1, 2	908.7	30.2%	4.60%	41.8
3	**Other Long-Term Debt Provision**	1	735.3	24.4%	4.60%	33.8
4	**Total Debt**	3	1,654.6	55.0%	4.63%	76.6
5	**Common Equity**	3	1,353.8	45.0%	8.78%	118.9
6	**Rate Base Financed by Capital Structure**		3,008.4	87.5%	6.50%	195.4
7	**Adjustment for Lesser of UNL or ARC**	4	431.0	12.5%	4.95%	21.3
8	**Rate Base**	5	3,439.4	100%	6.30%	216.8

Notes:

1 Long- and short-term debt cost rates as proposed by OPG were approved by the OEB (Ex. O1-1-1 P. 8).

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 4, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6 and Ex. L-03.1-20 VECC-005, Table 5, line 1.

3 The OEB approved a Debt / Equity ratio of 55% debt, 45% equity (OEB Decision and Order P. 100) and a 8.78% return on common equity (OEB Decision and Order P. 111).

4 Col. (a) is per PAO App. A, Table 9, line 19, col. (f) less PAO App. A, Table 10, line 19, col. (f).
Col. (c) reflects update to Nuclear Liabilities for actual 2017-2021 ONFA contribution schedule, year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

5 Col. (a) is per Table 2, line 4, col. (c).

Numbers may not add due to rounding.

Table 13
Capitalization and Cost of Capital
Summary of Approved Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2019

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	10.6	0.4%	3.75%	1.1
2	**Existing/Planned Long-Term Debt**	1, 2	1,000.0	33.3%	4.52%	45.2
3	**Other Long-Term Debt Provision**	1	640.4	21.3%	4.52%	29.0
4	**Total Debt**	3	1,651.0	55.0%	4.56%	75.3
5	**Common Equity**	3	1,350.8	45.0%	8.78%	118.6
6	**Rate Base Financed by Capital Structure**		3,001.9	89.4%	6.46%	193.9
7	**Adjustment for Lesser of UNL or ARC**	4	356.8	10.6%	4.95%	17.7
8	**Rate Base**	5	3,358.7	100%	6.30%	211.5

Notes:

1 Long- and short-term debt cost rates as proposed by OPG were approved by the OEB (Ex. O1-1-1 P. 8).

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 3, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6 and Ex. L-03.1-20 VECC-005, Table 5, line 1.

3 The OEB approved a Debt / Equity ratio of 55% debt, 45% equity (OEB Decision and Order P. 100) and a 8.78% return on common equity (OEB Decision and Order P. 111).

4 Col. (a) is per PAO App. A, Table 9, line 29, col. (f) less PAO App. A, Table 10, line 29, col. (f).
Col. (c) reflects update to Nuclear Liabilities for actual 2017-2021 ONFA contribution schedule, year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

5 Col. (a) is per Table 3, line 4, col. (c).

Table 14
Capitalization and Cost of Capital
Summary of Approved Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2020

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	17.8	0.3%	3.80%	1.8
2	**Existing/Planned Long-Term Debt**	1, 2	1,697.6	24.1%	4.49%	76.3
3	**Other Long-Term Debt Provision**	1	2,154.6	30.6%	4.49%	96.8
4	**Total Debt**	3	3,870.0	55.0%	4.52%	174.9
5	**Common Equity**	3	3,166.4	45.0%	8.78%	278.0
6	**Rate Base Financed by Capital Structure**		7,036.3	96.1%	6.44%	452.9
7	**Adjustment for Lesser of UNL or ARC**	4	282.7	3.9%	4.95%	14.0
8	**Rate Base**	5	7,319.0	100%	6.38%	466.9

Notes:

1 Long- and short-term debt cost rates as proposed by OPG were approved by the OEB (Ex. O1-1-1 P. 8).

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 2, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6 and Ex. L-03.1-20 VECC-005, Table 5, line 1.

3 The OEB approved a Debt / Equity ratio of 55% debt, 45% equity (OEB Decision and Order P. 100) and a 8.78% return on common equity (OEB Decision and Order P. 111).

4 Col. (a) is per PAO App. A, Table 9, line 39, col. (f) less PAO App. A, Table 10, line 39, col. (f).
Col. (c) reflects update to Nuclear Liabilities for actual 2017-2021 ONFA contribution schedule, year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

5 Col. (a) is per Table 4, line 4, col. (c).

Table 15
Capitalization and Cost of Capital
Summary of Approved Nuclear Capitalization and Cost of Capital
Calendar Year Ending December 31, 2021

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	18.3	0.2%	3.65%	1.9
2	**Existing/Planned Long-Term Debt**	1, 2	1,679.1	22.5%	4.48%	75.2
3	**Other Long-Term Debt Provision**	1	2,411.8	32.3%	4.48%	108.0
4	**Total Debt**	3	4,109.2	55.0%	4.50%	185.1
5	**Common Equity**	3	3,362.0	45.0%	8.78%	295.2
6	**Rate Base Financed by Capital Structure**		7,471.2	97.4%	6.43%	480.3
7	**Adjustment for Lesser of UNL or ARC**	4	202.9	2.6%	4.95%	10.0
8	**Rate Base**	5	7,674.1	100%	6.39%	490.3

Notes:

1 Long- and short-term debt cost rates as proposed by OPG were approved by the OEB (Ex. O1-1-1 P. 8).

2 Col. (a) is calculated by multiplying the total principal (Ex. C1-1-1, Table 1, col. (a)) by the ratio of nuclear rate base financed by capital structure to total rate base financed by capital structure. Nuclear proportion of total rate base is calculated as line 6 divided by the sum of line 6 and Ex. L-03.1-20 VECC-005, Table 5, line 1.

3 The OEB approved a Debt / Equity ratio of 55% debt, 45% equity (OEB Decision and Order P. 100) and a 8.78% return on common equity (OEB Decision and Order P. 111).

4 Col. (a) is per PAO App. A, Table 9, line 49, col. (f) less PAO App. A, Table 10, line 49, col. (f).
Col. (c) reflects update to Nuclear Liabilities for actual 2017-2021 ONFA contribution schedule, year-end 2016 asset retirement obligation adjustment and discount rate as reflected in Ex. J21.2 (OEB Decision and Order P. 98).

5 Col. (a) is per Table 5, line 4, col. (c).

Table 16
2017 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	143.1	(41.2)	101.9
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	367.0	(23.8)	343.2
3	**Nuclear Waste Management Expenses**	4	63.9	(11.0)	52.9
4	**Receipts from Nuclear Segregated Funds**		84.4	0.0	84.4
5	**Pension and OPEB Accrual**		291.2	0.0	291.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	5	(24.0)	24.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	5	(2.2)	2.2	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	25.9	(0.9)	25.0
9	**Taxable SR&ED Investment Tax Credits**		18.4	0.0	18.4
10	**Other**		63.7	0.0	63.7
11	**Total Additions**		888.4	(9.5)	878.9
	Deductions for Regulatory Tax Purposes:				
12	**CCA**	7	394.2	(41.4)	352.8
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		217.5	0.0	217.5
14	**Contributions to Nuclear Segregated Funds**	8	0.0	102.5	102.5
15	**Pension Plan Contributions**		200.0	0.0	200.0
16	**OPEB/SPP Payments**		91.1	0.0	91.1
17	**Deductible SR&ED Qualifying Expenditures**		27.7	0.0	27.7
18	**Other**		22.0	0.0	22.0
19	**Total Deductions**		952.6	61.1	1,013.7
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		78.9	(111.9)	(33.0)
21	**Tax Loss Carry-Over**	9	(34.3)	67.3	33.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		44.6	(44.6)	0.0
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		6.7	(6.7)	0.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		4.5	(4.5)	0.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	0.0	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(7.3)	(11.1)	(18.4)
	Income Tax Rate:				
27	**Federal Tax**		15.00%	0.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
29	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 16a.

Table 16a
Notes to Table 16
Calculation of Regulatory Income Taxes
Year Ending December 31, 2017

Notes:
1 As provided in PAO App. A, Table 21 and 21a.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 1, line 12	133.5	(18.4)	115.1
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 1, line 20	(16.9)	11.6	(5.3)
3a		line 1a - line 2a	150.4	(30.0)	120.4
4a	Additions for Regulatory Tax Purposes	line 11	888.4	(9.5)	878.9
5a	Deductions for Regulatory Tax Purposes	line 19	952.6	61.1	1,013.7
6a		line 3a + line 4a - line 5a	86.2	(100.7)	(14.5)
7a	Regulatory Income Taxes - Federal	(lines 6a + 25) x line 27	11.8	(16.8)	(4.9)
8a	Regulatory Income Taxes - Provincial	(lines 6a + 25) x line 28	7.9	(11.2)	(3.3)
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	1.3	(28.0)	(26.6)
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 7a x (-1)	(5.1)	10.1	4.9
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 8a x (-1)	(3.4)	6.7	3.3
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	(8.6)	16.8	8.2
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	6.7	(6.7)	0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	4.5	(4.5)	0.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(7.3)	(11.1)	(18.4)
18a	After Tax Return on Equity	line 1a	133.5	(18.4)	115.1
19a	Less: Bruce Lease Net Revenues	line 2a	(16.9)	11.6	(5.3)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(7.3)	(11.1)	(18.4)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	143.1	(41.1)	102.0

3 PAO App. A, Table 1, line 17.
4 Adjustment to used fuel storage and disposal variable expenses and low and intermediate level waste management variable expenses per PAO App. A Table 1a, Note 4 (line b) and PAO App A, Table 1a, Note 5.
5 Propoesd amortization of Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account over the two year period 2017 to 2018 is removed. The accounts will be amortized in 2019 through 2021 (PAO App. E, Table 1, cols. (e)-(h), line 16).
6 PAO App. A, Table 1, line 13.
7 Adjustment to reflect changes to Capital Cost Allowance resulting from OEB-adjusted capital in-service additions per PAO App. A, Table 9 (i.e. Ex. J21.1 Att. 2 update, Auxiliary Heating System and Operations Support Building disallowances, and 10% reduction in forecast nuclear operations and support services in-service additions).
8 Adjustment to reflect actual 2017-2021 ONFA contribution schedule per Ex. J20.8, Chart 1, line 4 (OEB's Decision and Order P. 98).
9 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR Term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR Term, with any remaining tax losses carried forward to future test periods.

Table 17

2018 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
				(a)	(b)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	134.7	(27.0)	107.7
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	395.0	(2.6)	392.4
3	**Nuclear Waste Management Expenses**	4	63.2	(10.8)	52.4
4	**Receipts from Nuclear Segregated Funds**		85.7	0.0	85.7
5	**Pension and OPEB Accrual**		298.7	0.0	298.7
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	5	(24.0)	24.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	5	(2.2)	2.2	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	22.1	(0.8)	21.3
9	**Taxable SR&ED Investment Tax Credits**		18.4	0.0	18.4
10	**Other**		49.2	0.0	49.2
11	**Total Additions**		906.2	12.0	918.2
	Deductions for Regulatory Tax Purposes:				
12	**CCA**	7	504.4	(25.3)	479.2
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		227.9	0.0	227.9
14	**Contributions to Nuclear Segregated Funds**	8	0.0	102.5	102.5
15	**Pension Plan Contributions**		202.9	0.0	202.9
16	**OPEB/SPP Payments**		95.7	0.0	95.7
17	**Deductible SR&ED Qualifying Expenditures**		27.7	0.0	27.7
18	**Other**		0.0	0.0	0.0
19	**Total Deductions**		1,058.7	77.2	1,136.0
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		(17.9)	(92.2)	(110.1)
21	**Tax Loss Carry-Over**	9	17.9	92.2	110.1
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		(0.0)	0.0	0.0
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		(0.0)	0.0	0.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		(0.0)	0.0	0.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	0.0	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(18.4)	0.0	(18.4)
	Income Tax Rate:				
27	**Federal Tax**		15.00%	0.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
29	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 17a.

Table 17a
Notes to Table 17
Calculation of Regulatory Income Taxes
Year Ending December 31, 2018

Notes:
1 As provided in App. A, Table 21 and 21a.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 2, line 12	136.0	(17.1)	118.9
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 2, line 20	(17.1)	9.9	(7.3)
3a		line 1a - line 2a	153.1	(27.0)	126.1
4a	Additions for Regulatory Tax Purposes	line 11	906.2	12.0	918.2
5a	Deductions for Regulatory Tax Purposes	line 19	1,058.7	77.2	1,136.0
6a		line 3a + line 4a - line 5a	0.5	(92.2)	(91.7)
7a	Regulatory Income Taxes - Federal	(lines 6a + 25) x line 27	(2.7)	(13.8)	(16.5)
8a	Regulatory Income Taxes - Provincial	(lines 6a + 25) x line 28	(1.8)	(9.2)	(11.0)
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	(22.9)	(23.0)	(45.9)
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 7a x (-1)	2.7	13.8	16.5
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 8a x (-1)	1.8	9.2	11.0
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	4.5	23.0	27.5
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	0.0	0.0	0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(18.4)	0.0	(18.4)
18a	After Tax Return on Equity	line 1a	136.0	(17.1)	118.9
19a	Less: Bruce Lease Net Revenues	line 2a	(17.1)	9.9	(7.3)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(18.4)	0.0	(18.4)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	134.7	(27.0)	107.7

3 PAO App. A, Table 2, line 17.
4 Adjustment to used fuel storage and disposal variable expenses and low and intermediate level waste management variable expenses per PAO App. A Table 2a, Note 4 (line b) and PAO App A, Table 2a, Note 5.
5 Propoesd amortization of Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account over the two year period 2017 to 2018 is removed. The accounts will be amortized in 2019 through 2021 (PAO App. E, Table 1, cols. (e)-(h), line 16).
6 PAO App. A, Table 2, line 13.
7 Adjustment to reflect changes to Capital Cost Allowance resulting from OEB-adjusted capital in-service additions per PAO App. A, Table 9 (i.e. Ex. J21.1 Att. 2 update, Auxiliary Heating System and Operations Support Building disallowances, and 10% reduction in forecast nuclear operations and support services in-service additions).
8 Adjustment to reflect actual 2017-2021 ONFA contribution schedule per Ex. J20.8, Chart 1, line 4 (OEB's Decision and Order P. 98).
9 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR Term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the IR Term, with any remaining tax losses carried forward to future test periods.

Numbers may not add due to rounding.

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Appendix A
Table 18

Table 18
2019 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	142.7	(21.9)	120.8
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	400.3	13.8	414.0
3	**Nuclear Waste Management Expenses**	4	77.9	(13.0)	64.8
4	**Receipts from Nuclear Segregated Funds**		120.4	0.0	120.4
5	**Pension and OPEB Accrual**		343.3	0.0	343.3
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	5	0.0	(16.0)	(16.0)
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	5	0.0	(1.4)	(1.4)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	18.3	(0.6)	17.7
9	**Taxable SR&ED Investment Tax Credits**		18.4	0.0	18.4
10	**Other**		38.4	0.0	38.4
11	**Total Additions**		1,016.9	(17.4)	999.6
	Deductions for Regulatory Tax Purposes:				
12	**CCA**	7	571.1	(13.9)	557.2
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		232.8	0.0	232.8
14	**Contributions to Nuclear Segregated Funds**	8	0.0	102.5	102.5
15	**Pension Plan Contributions**		243.5	0.0	243.5
16	**OPEB/SPP Payments**		99.9	0.0	99.9
17	**Deductible SR&ED Qualifying Expenditures**		27.7	0.0	27.7
18	**Other**		1.1	(0.0)	1.1
19	**Total Deductions**		1,176.1	88.6	1,264.7
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		(16.4)	(127.9)	(144.3)
21	**Tax Loss Carry-Over**	9	16.4	127.9	144.3
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		(0.0)	0.0	0.0
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		(0.0)	0.0	0.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		(0.0)	0.0	0.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	0.0	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(18.4)	0.0	(18.4)
	Income Tax Rate:				
27	**Federal Tax**		15.00%	0.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
29	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 18a.

Table 18a
Notes to Table 18
Calculation of Regulatory Income Taxes
Year Ending December 31, 2019

Notes:
1 As provided in App. A, Table 21 and 21a.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 3, line 12	133.7	(15.1)	118.6
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 3, line 20	(27.4)	6.8	(20.6)
3a		line 1a - line 2a	161.1	(21.9)	139.2
4a	Additions for Regulatory Tax Purposes	line 11	1,016.9	(17.4)	999.6
5a	Deductions for Regulatory Tax Purposes	line 19	1,176.1	88.6	1,264.7
6a		line 3a + line 4a - line 5a	2.0	(127.9)	(125.9)
7a	Regulatory Income Taxes - Federal	(lines 6a + 25) x line 27	(2.5)	(19.2)	(21.6)
8a	Regulatory Income Taxes - Provincial	(lines 6a + 25) x line 28	(1.6)	(12.8)	(14.4)
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	(22.5)	(32.0)	(54.5)
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 7a x (-1)	2.5	19.2	21.6
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 8a x (-1)	1.6	12.8	14.4
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	4.1	32.0	36.1
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	0.0	0.0	0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	0.0	0.0	0.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(18.4)	0.0	(18.4)
18a	After Tax Return on Equity	line 1a	133.7	(15.1)	118.6
19a	Less: Bruce Lease Net Revenues	line 2a	(27.4)	6.8	(20.6)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(18.4)	0.0	(18.4)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	142.7	(21.9)	120.8

3 PAO App. A, Table 3, line 17.
4 Adjustment to used fuel storage and disposal variable expenses and low and intermediate level waste management variable expenses per PAO App. A Table 3a, Note 4 (line b) and PAO App A, Table 3a, Note 5.
5 Propoesd amortization of Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account over the two year period 2017 to 2018 is removed. The accounts will be amortized in 2019 through 2021 (PAO App. E, Table 1, cols. (e)-(h), line 16).
6 PAO App. A, Table 3, line 13.
7 Adjustment to reflect changes to Capital Cost Allowance resulting from OEB-adjusted capital in-service additions per PAO App. A, Table 9 (i.e. Ex. J21.1 Att. 2 update, Auxiliary Heating System and Operations Support Building disallowances, and 10% reduction in forecast nuclear operations and support services in-service additions).
8 Adjustment to reflect actual 2017-2021 ONFA contribution schedule per Ex. J20.8, Chart 1, line 4 (OEB's Decision and Order P. 98).
9 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR Term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR Term, with any remaining tax losses carried forward to future test periods.

Table 19

2020 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	391.1	(111.4)	279.7
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	541.2	49.2	590.3
3	**Nuclear Waste Management Expenses**	4	66.5	(10.3)	56.1
4	**Receipts from Nuclear Segregated Funds**		152.0	0.0	152.0
5	**Pension and OPEB Accrual**		352.3	0.0	352.3
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	5	0.0	(16.0)	(16.0)
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	5	0.0	(1.4)	(1.4)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	14.5	(0.5)	14.0
9	**Taxable SR&ED Investment Tax Credits**		18.4	0.0	18.4
10	**Other**		38.6	0.0	38.6
11	**Total Additions**		1,183.4	20.9	1,204.3
	Deductions for Regulatory Tax Purposes:				
12	**CCA**	7	594.8	(12.6)	582.2
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		283.6	0.0	283.6
14	**Contributions to Nuclear Segregated Funds**	8	0.0	102.5	102.5
15	**Pension Plan Contributions**		247.9	0.0	247.9
16	**OPEB/SPP Payments**		104.3	0.0	104.3
17	**Deductible SR&ED Qualifying Expenditures**		27.7	0.0	27.7
18	**Other**		5.8	0.0	5.8
19	**Total Deductions**		1,264.2	89.9	1,354.1
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		310.3	(180.4)	129.9
21	**Tax Loss Carry-Over**	9	0.0	(129.9)	(129.9)
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		310.3	(310.3)	0.0
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		46.5	(46.5)	0.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		31.0	(31.0)	0.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	0.0	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		59.2	(77.6)	(18.4)
	Income Tax Rate:				
27	**Federal Tax**		15.00%	0.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
29	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 19a.

Numbers may not add due to rounding.

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Appendix A
Table 19a

Table 19a
Notes to Table 19
Calculation of Regulatory Income Taxes
Year Ending December 31, 2020

Notes:
1 As provided in App. A, Table 21 and 21a.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 4, line 12	308.1	(30.1)	278.0
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 4, line 20	(23.8)	3.7	(20.1)
3a		line 1a - line 2a	331.9	(33.8)	298.1
4a	Additions for Regulatory Tax Purposes	line 11	1,183.4	20.9	1,204.3
5a	Deductions for Regulatory Tax Purposes	line 19	1,264.2	89.9	1,354.1
6a		line 3a + line 4a - line 5a	251.1	(102.8)	148.3
7a	Regulatory Income Taxes - Federal	(lines 6a + 25) x line 27	46.5	(27.1)	19.5
8a	Regulatory Income Taxes - Provincial	(lines 6a + 25) x line 28	31.0	(18.0)	13.0
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	59.2	(45.1)	14.1
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 7a x (-1)	0.0	(19.5)	(19.5)
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 8a x (-1)	0.0	(13.0)	(13.0)
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	0.0	(32.5)	(32.5)
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	46.5	(46.5)	0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	31.0	(31.0)	0.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	59.2	(77.6)	(18.4)
18a	After Tax Return on Equity	line 1a	308.1	(30.1)	278.0
19a	Less: Bruce Lease Net Revenues	line 2a	(23.8)	3.7	(20.1)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	59.2	(77.6)	(18.4)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	391.1	(111.4)	279.7

3 PAO App. A, Table 4, line 17.
4 Adjustment to used fuel storage and disposal variable expenses and low and intermediate level waste management variable expenses per PAO App. A Table 4a, Note 4 (line b) and PAO App A, Table 4a, Note 5.
5 Propoesd amortization of Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account over the two year period 2017 to 2018 is removed. The accounts will be amortized in 2019 through 2021 (PAO App. E, Table 1, cols. (e)-(h), line 16).
6 PAO App. A, Table 4, line 13.
7 Adjustment to reflect changes to Capital Cost Allowance resulting from OEB-adjusted capital in-service additions per PAO App. A, Table 9 (i.e. Ex. J21.1 Att. 2 update, Auxiliary Heating System and Operations Support Building disallowances, and 10% reduction in forecast nuclear operations and support services in-service additions).
8 Adjustment to reflect actual 2017-2021 ONFA contribution schedule per Ex. J20.8, Chart 1, line 4 (OEB's Decision and Order P. 98).
9 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR Term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR Term, with any remaining tax losses carried forward to future test periods.

Table 20

2021 Summary of Changes in Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
	Determination of Regulatory Taxable Income				
1	**Regulatory Earnings Before Tax**	2	361.6	(44.4)	317.2
	Additions for Regulatory Tax Purposes:				
2	**Depreciation and Amortization**	3	316.7	(28.3)	288.3
3	**Nuclear Waste Management Expenses**	4	68.8	(10.3)	58.5
4	**Receipts from Nuclear Segregated Funds**		193.7	0.0	193.7
5	**Pension and OPEB Accrual**		359.2	0.0	359.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	5	0.0	(16.0)	(16.0)
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	5	0.0	(1.4)	(1.4)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	12.4	(2.3)	10.0
9	**Taxable SR&ED Investment Tax Credits**		18.4	0.0	18.4
10	**Other**		40.2	0.0	40.2
11	**Total Additions**		1,009.3	(58.4)	950.9
	Deductions for Regulatory Tax Purposes:				
12	**CCA**	7	597.0	(22.6)	574.4
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		317.0	0.0	317.0
14	**Contributions to Nuclear Segregated Funds**	8	0.0	102.5	102.5
15	**Pension Plan Contributions**		250.6	0.0	250.6
16	**OPEB/SPP Payments**		108.5	0.0	108.5
17	**Deductible SR&ED Qualifying Expenditures**		27.7	0.0	27.7
18	**Other**		16.4	(0.0)	16.4
19	**Total Deductions**		1,317.3	79.9	1,397.2
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		53.6	(182.6)	(129.0)
21	**Tax Loss Carry-Over**	9	0.0	129.0	129.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		53.6	(53.6)	0.0
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		8.0	(8.0)	0.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		5.4	(5.4)	0.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	0.0	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(5.0)	(13.4)	(18.4)
	Income Tax Rate:				
27	**Federal Tax**		15.00%	0.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	0.00%	10.00%
29	**Total Income Tax Rate**		25.00%	0.00%	25.00%

For notes see Table 20a.

Table 20a
Notes to Table 20
Calculation of Regulatory Income Taxes
Year Ending December 31, 2021

Notes:
1 As provided in App. A, Table 21 and 21a.
2 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference for OEB Approved	OPG Proposed	OEB Adjustment	OEB Approved
			(a)	(b)	(c)
			Note 1		
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 5, line 12	328.6	(33.4)	295.2
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 5, line 20	(38.1)	(2.4)	(40.4)
3a		line 1a - line 2a	366.6	(31.0)	335.6
4a	Additions for Regulatory Tax Purposes	line 11	1,009.3	(58.4)	950.9
5a	Deductions for Regulatory Tax Purposes	line 19	1,317.3	79.9	1,397.2
6a		line 3a + line 4a - line 5a	58.6	(169.2)	(110.6)
7a	Regulatory Income Taxes - Federal	(lines 6a + 25) x line 27	8.0	(27.4)	(19.4)
8a	Regulatory Income Taxes - Provincial	(lines 6a + 25) x line 28	5.4	(18.3)	(12.9)
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	(5.0)	(45.7)	(50.7)
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 7a x (-1)	0.0	19.4	19.4
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 8a x (-1)	0.0	12.9	12.9
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	0.0	32.3	32.3
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	8.0	(8.0)	0.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	5.4	(5.4)	0.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	0.0	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(5.0)	(13.4)	(18.4)
18a	After Tax Return on Equity	line 1a	328.6	(33.4)	295.2
19a	Less: Bruce Lease Net Revenues	line 2a	(38.1)	(2.4)	(40.4)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(5.0)	(13.4)	(18.4)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	361.6	(44.4)	317.2

3 PAO App. A, Table 5, line 17.
4 Adjustment to used fuel storage and disposal variable expenses and low and intermediate level waste management variable expenses per PAO App. A Table 5a, Note 4 (line b) and PAO App A, Table 5a, Note 5.
5 Propoesd amortization of Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account over the two year period 2017 to 2018 is removed. The accounts will be amortized in 2019 through 2021 (PAO App. E, Table 1, cols. (e)-(h), line 16).
6 PAO App. A, Table 5, line 13.
7 Adjustment to reflect changes to Capital Cost Allowance resulting from OEB-adjusted capital in-service additions per PAO App. A, Table 9 (i.e. Ex. J21.1 Att. 2 update, Auxiliary Heating System and Operations Support Building disallowances, and 10% reduction in forecast nuclear operations and support services in-service additions).
8 Adjustment to reflect actual 2017-2021 ONFA contribution schedule per Ex. J20.8, Chart 1, line 4 (OEB's Decision and Order P. 98).
9 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the IR Term, the loss is applied (carried back or carried forward) to reduce the nuclear business unit’s taxable income in other years of the IR Term, with any remaining tax losses carried forward to future test periods.
10 As at December 31, 2021, the amount of tax losses carried forward to future test periods is $286.4M (PAO Table 16, line 21, col. (c) + PAO Table 17, line 21, col. (c) + PAO Table 18, line 21, col. (c) + PAO Table 19, line 21, col. (c) + PAO Table 20, line 21, col. (c))

Numbers may not add due to rounding.

Table 21

2017 - 2021 Summary of Proposed Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Line No.	Particulars	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	143.1	134.7	142.7	391.1	361.6
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**	2	367.0	395.0	400.3	541.2	316.7
3	**Nuclear Waste Management Expenses**	2	63.9	63.2	77.9	66.5	68.8
4	**Receipts from Nuclear Segregated Funds**	2	84.4	85.7	120.4	152.0	193.7
5	**Pension and OPEB Accrual**	2	291.2	298.7	343.3	352.3	359.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	2	(24.0)	(24.0)	0.0	0.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	2	(2.2)	(2.2)	0.0	0.0	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	2	25.9	22.1	18.3	14.5	12.4
9	**Taxable SR&ED Investment Tax Credits**	2	18.4	18.4	18.4	18.4	18.4
10	**Other**	2	63.7	49.2	38.4	38.6	40.2
11	**Total Additions**		888.4	906.2	1,016.9	1,183.4	1,009.3
	Deductions for Regulatory Tax Purposes:						
12	**CCA**	2	394.2	504.4	571.1	594.8	597.0
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	2	217.5	227.9	232.8	283.6	317.0
14	**Contributions to Nuclear Segregated Funds**	2	0.0	0.0	0.0	0.0	0.0
15	**Pension Plan Contributions**	2	200.0	202.9	243.5	247.9	250.6
16	**OPEB/SPP Payments**	2	91.1	95.7	99.9	104.3	108.5
17	**Deductible SR&ED Qualifying Expenditures**	2	27.7	27.7	27.7	27.7	27.7
18	**Other**	3	22.0	0.0	1.1	5.8	16.4
19	**Total Deductions**		952.6	1,058.7	1,176.1	1,264.2	1,317.3
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		78.9	(17.9)	(16.4)	310.3	53.6
21	**Tax Loss Carry-Over**	4	(34.3)	17.9	16.4	0.0	0.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		44.6	0.0	(0.0)	310.3	53.6
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		6.7	(0.0)	(0.0)	46.5	8.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		4.5	(0.0)	(0.0)	31.0	5.4
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(7.3)	(18.4)	(18.4)	59.2	(5.0)
	Income Tax Rate:						
27	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
29	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 21a.

Table 21a
Notes to Table 21
Calculation of Regulatory Income Taxes
2017 - 2021 Summary of Proposed Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)

Notes:
1 Regulatory Earnings Before Tax are calculated as follows:

Line No.	Item	Reference	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	PAO App. A, Table 6, line 12	133.5	136.0	133.7	308.1	328.6
2a	Less: Bruce Lease Net Revenues	PAO App. A, Table 6, line 20	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
3a		line 1a - line 2a	150.4	153.1	161.1	331.9	366.6
4a	Additions for Regulatory Tax Purposes	line 11	888.4	906.2	1,016.9	1,183.4	1,009.3
5a	Deductions for Regulatory Tax Purposes	line 19	952.6	1,058.7	1,176.1	1,264.2	1,317.3
6a		line 3a + line 4a - line 5a	86.2	0.5	2.0	251.1	58.6
7a	Regulatory Income Taxes - Federal	Col. (a): (lines 6a + 13a + 25) x line 27 / (1 - line 29) Cols. (b) to (c): (lines 6a + 25) x line 27 Col. (d) to (e): (lines 6a + 13a + 25) x line 27 / (1 - line 29)	11.8	(2.7)	(2.5)	46.5	8.0
8a	Regulatory Income Taxes - Provincial	Col. (a): (lines 6a + 13a + 25) x line 28 / (1 - line 29) Cols. (b) to (c): (lines 6a + 25) x line 28 Col. (d) to (e): (lines 6a + 13a + 25) x line 28 / (1 - line 29)	7.9	(1.8)	(1.6)	31.0	5.4
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	1.3	(22.9)	(22.5)	59.2	(5.0)
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	Col. (a): sum of cols (b) to (c) on line 11a x (-1) Cols. (b) to (c): line 7a x (-1)	(5.1)	2.7	2.5	0.0	0.0
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	Col. (a): sum of cols (b) to (c) on line 12a x (-1) Cols. (b) to (c): line 8a x (-1)	(3.4)	1.8	1.6	0.0	0.0
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	(8.6)	4.5	4.1	0.0	0.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	6.7	0.0	0.0	46.5	8.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	4.5	0.0	0.0	31.0	5.4
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(7.3)	(18.4)	(18.4)	59.2	(5.0)
18a	After Tax Return on Equity	line 1a	133.5	136.0	133.7	308.1	328.6
19a	Less: Bruce Lease Net Revenues	line 2a	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(7.3)	(18.4)	(18.4)	59.2	(5.0)
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	143.1	134.7	142.7	391.1	361.6

2 Ex. N2-1-1, Table 2.
3 Reflects the impact of updated fuel expense per PAO App. A, Table 6a, Note 3, line (f) on fifty per cent of nuclear fuel expense incurred in a given year which is not deductible for tax purposes until the following year. Changes as compared to Ex. N2-1-1, Table 2, line 18 are: $1.7M, -$0.1M, $0.0M, $0.1M and -$0.1M in 2017 to 2021, respectively.

4 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the test period, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the test period, with any remaining tax losses carried forward to future test periods.

Table 1

Payment Amounts and Riders – Hydroelectric[1]

January 1, 2017 to December 31, 2021

Line No.	Description	Note	2017	2018	Illustrative Payment Amounts[1] 2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
1	**Price Escalator (I-Factor)**	2	**1.70%**	**1.20%**	**1.20%**	**1.20%**	**1.20%**
2	Productivity Factor	3	0.00%	0.00%	0.00%	0.00%	0.00%
3	**Stretch Factor**	4	**0.30%**	**0.30%**	**0.30%**	**0.30%**	**0.30%**
4	**Price Cap Index** (line 1 - line 2 - line 3)		**1.40%**	**0.90%**	**0.90%**	**0.90%**	**0.90%**
5	**Prior Year Hydroelectric Payment Amount ($/MWh)**	5	41.09	41.67	42.05	42.43	42.81
6	**Prior Year Price Cap Adjusted Hydroelectric Payment Amount ($/MWh)**	6	41.67	42.05	42.43	42.81	43.20
7	**Hydroelectric Payment Rider A ($/MWh)**	7			0.96	0.96	0.96
8	**Hydroelectric Payment Rider B ($/MWh)**	8			0.23	0.23	0.23
9	**Total of Hydroelectric Payment Amounts Plus Riders** (line 6 + line 7 + line 8)		41.67	42.05	43.62	44.00	44.39

Notes:

1 Payment Amounts for 2019-2021 are ilustrative only - final payment amounts will be determined annually, using OEB approved I-factor values.

2 2017 and 2018 Price Escalator (I-Factor) set as per OEB Decision and Order P. 123. 2019-2021 I-factor values are set to 2018 OEB-approved I-factor for the purpose of WAPA smoothing only. Final I-factor values will be approved annually by the OEB.

3 Per OEB Decision and Order P. 128.

4 Per OEB Decision and Order P. 129.

5 2017 is the weighted average of tax loss adjusted approved hydroelectric payment amounts from EB-2013-0321. See Ex. I1-2-1 Table 1a, Ex. O1-1-1, P. 15, and OEB Decision and Order P. 121-122.

6 Prior Year Hydroelectric Payment Amount (line 5) escalated by the Price Cap Index (Line 4).

7 Per PAO App. D, Table 1, line 14.

8 Per PAO App. F, Table 1, line 12.

Table 1
Payment Amounts - Nuclear
Test Period January 1, 2017 to December 31, 2021

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	PAYMENT AMOUNT:						
1	**Revenue Requirement Net of Stretch Factor ($M)**	1	2,973.0	3,032.4	3,116.5	3,579.1	3,173.9
2	**Forecast Production (TWh)**	2	38.1	38.5	39.0	37.4	35.4
3	**Nuclear Payment Amount ($/MWh)**	3	80.65	83.10	76.17	79.70	83.67
4	**Forecast Nuclear Revenue Received** (line 2 x line 3)		3,072.6	3,196.9	2,972.6	2,977.2	2,960.5
5	**Nuclear Revenue Requirement Deferred** (line 1 - line 4)	4	(62)	(165)	144	602	213

Notes:
1 PAO App. A, Tables 1 to 5, line 26, col. (c).
2 Per OEB Decision and Order P. 11-12.
3 PAO App. I, Table 2, line 4.
4 Col. (a) prorated by the ratio of June-December 2017 volumes (23.9 MWh per Ex. E2-1-1, Table 2, line 3, col. (f) to (l)) over Total 2017 volumes (38.1 MWh Per Ex. E2-1-1, Table 1, line 3, col. (e)) to reflect an effective date of June 1, 2017.

Numbers may not add due to rounding.

Table 1
Calculation of Deferral and Variance Account Recovery Payment Riders - Regulated Hydroelectric Payment Rider A ($M)

Line No.	Account	Note	Audited Year End Balance 2015	EB-2014-0370 Approved Amortization 2016	(a)-(b) 2015 Approved Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2019	Amortization Jan - Dec 2020	Amortization Jan - Dec 2021	(e)+(f)+(g) Amortization Jan 2019 - Dec 2021	(c)-(h) Unamortized Approved Balance At Dec 31, 2021
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1	Note 2							
1	**Hydroelectric Water Conditions Variance**		(23.0)	(5.6)	(17.3)	36	(5.8)	(5.8)	(5.8)	(17.3)	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**		(24.2)	(11.0)	(13.2)	36	(4.4)	(4.4)	(4.4)	(13.2)	0.0
3	**Hydroelectric Incentive Mechanism Variance**		(1.7)	(1.7)	(0.1)	36	(0.0)	(0.0)	(0.0)	(0.1)	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**		114.4	31.9	82.5	36	27.5	27.5	27.5	82.5	0.0
5	**Income and Other Taxes Variance - Hydroelectric**		(0.1)	(0.1)	(0.0)	36	(0.0)	(0.0)	(0.0)	(0.0)	0.0
6	**Capacity Refurbishment Variance - Hydroelectric**		83.2	79.9	3.3	36	1.1	1.1	1.1	3.3	0.0
7	**Pension and OPEB Cost Variance - Hydroelectric - Future (Remaining YE 2012 Balance)**		9.5	1.1	8.4	72	0.7	0.7	0.7	2.1	6.3
8	**Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions**		32.5	5.9	26.6	30	3.9	3.9	3.9	11.8	14.8
9	**Pension & OPEB Cash Versus Accrual Differential Deferral - Hydroelectric**	3	44.2	0.0	44.2	N/A	0.0	0.0	0.0	0.0	44.2
10	**Pension & OPEB Cash Payment Variance - Hydroelectric**		4.3	0.0	4.3	36	1.4	1.4	1.4	4.3	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**		16.5	3.0	13.5	36	4.5	4.5	4.5	13.5	0.0
12	**Total**		255.5	103.4	152.1					86.8	65.2
13	**Forecast Production (TWh)**	4								90.7	
14	**Hydroelectric Payment Rider A ($/MWh)** (line 12 / line 13)									0.96	

Notes:
1 Per Ex. H1-1-1 Table 1, col. (b).
2 From EB-2014-0370 Payment Amounts Order App. A Table 1, col. (f).
3 Account not included for disposition in this application as discussed in Ex. H1-1-1.
4 2015 Actual Production of 30.2 TWh divided by 12 months multiplied by 36 months.

Numbers may not add due to rounding.

Table 1

Calculation of Deferral and Variance Account Recovery Payment Riders - Nuclear Payment Rider A ($M)

Line No.	Account	Note	Audited Year End Balance 2015	EB-2014-0370 Approved Amortization 2016	(a)-(b) 2015 Approved Balance Less 2016 Approved Amortization	Recovery Period (months)	Amortization Jan - Dec 2019	Amortization Jan - Dec 2020	Amortization Jan - Dec 2021	(e)+(f)+(g) Amortization Jan 2019 - Dec 2021	(c)-(h) Unamortized Approved Balance At Dec 31, 2021
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1	Note 2							
1	**Nuclear Liability Deferral**		190.5	190.5	0.0	36	0.0	0.0	0.0	0.0	0.0
2	**Nuclear Development Variance**		3.3	1.6	1.7	36	0.6	0.6	0.6	1.7	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**		2.1	1.2	1.0	36	0.3	0.3	0.3	1.0	0.0
4	**Capacity Refurbishment Variance - Nuclear - Capital Portion**		(32.5)	5.0	(37.6)	36	(12.5)	(12.5)	(12.5)	(37.6)	0.0
5	**Capacity Refurbishment Variance - Nuclear - Non-Capital Portion**		(30.8)	0.8	(31.6)	36	(10.5)	(10.5)	(10.5)	(31.6)	0.0
6	**Bruce Lease Net Revenues Variance - Derivative Sub-Account**		(4.5)	64.1	(68.6)	36	(22.9)	(22.9)	(22.9)	(68.6)	0.0
7	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - EB-2012-0002**		18.7	18.7	0.0	36	0.0	0.0	0.0	0.0	0.0
8	**Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions**		103.1	82.5	20.6	36	6.9	6.9	6.9	20.6	0.0
9	**Income and Other Taxes Variance - Nuclear**		(13.1)	(8.8)	(4.3)	36	(1.4)	(1.4)	(1.4)	(4.3)	0.0
10	**Pension and OPEB Cost Variance - Nuclear - Future (Remaining YE 2012 Balance)**		193.2	21.5	171.7	72	14.3	14.3	14.3	42.9	128.8
11	**Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions**		622.0	113.1	508.9	30	75.4	75.4	75.4	226.2	282.7
12	**Pension & OPEB Cash Versus Accrual Differential Deferral - Nuclear**	3	271.1	0.0	271.1	N/A	0.0	0.0	0.0	0.0	271.1
13	**Pension & OPEB Cash Payment Variance - Nuclear**		23.4	0.0	23.4	36	7.8	7.8	7.8	23.4	0.0
14	**Pickering Life Extension Depreciation Variance**	4	5.2	5.2	0.0	N/A	0.0	0.0	0.0	0.0	0.0
15	**Nuclear Deferral and Variance Over/Under Recovery Variance**		81.7	37.6	44.1	36	14.7	14.7	14.7	44.1	0.0
16	**Total**		1,433.4	533.0	900.5					217.9	682.6
17	**Forecast Production (TWh)**	5								111.8	
18	**Nuclear Payment Rider A ($/MWh)** (line 16 / line 17)									1.95	

Notes:
1 Per Ex. H1-1-1 Table 1, col. (b).
2 From EB-2014-0370 Payment Amounts Order, App. A, Table 2, col. (f).
3 Account not included for disposition in this application as discussed in Ex. H1-1-1.
4 Account is terminated as of June 1, 2017.
5 PAO App. C, Table 1. Sum of nuclear production forecast from 2019 to 2021 (line 2, col. (c) + col. (d) + col. (e)).

Table 1

Regulated Hydroelectric Interim Period Shortfall Recovery Rider (Hydroelectric Payment Rider B)

Line No.	Description	Note	2017	2018
			(a)	(b)
	REVENUE SHORTFALL - JUNE 1, 2017 to FEBRUARY 28, 2018			
1	**Approved Payment Amount ($/MWh)**	1	41.67	42.05
	Interim Payment Amount			
2	Previously Regulated Hydroelectric Payment Amount ($/MWh)	2	40.20	40.20
3	Newly Regulated Hydroelectric Payment Amount ($/MWh)	3	41.93	41.93
	Payment Amount Increase			
4	Previously Regulated Hydroelectric Payment Amount ($/MWh) (line 1 - line 2)		1.47	1.85
5	Newly Regulated Hydroelectric Payment Amount ($/MWh) (line 1 - line 3)		(0.26)	0.12
6	Hydroelectric Production - Previously Regulated (TWh)	4	11.2	3.2
7	Hydroelectric Production - Newly Regulated (TWh)	5	6.0	1.8
	Revenue Shortfall June 1, 2017 to February 28, 2018			
8	Revenue Shortfall - Previously Regulated ($M) (line 4 x line 6)		16.5	6.0
9	Revenue Shortfall - Newly Regulated ($M) (line 5 x line 7)		(1.6)	0.2
10	Total Revenue Shortfall (line 8 + line 9)		**14.9**	**6.2**
	APPROVED PRODUCTION FORECAST - JANUARY 1, 2019 to DECEMBER 31, 2021			
11	**Total Forecast Production January 1, 2019 to December 31, 2021 (TWh)**	6		**90.6**
	HYDROELECTRIC PAYMENT RIDER B:			
12	**Hydroelectric Payment Rider B Effective January 1, 2019 ($/MWh)** (sum of line 10 / line 11)			**0.23**

Notes:

1 PAO App. B, Table 1, line 6.
2 EB-2013-0321 Payment Amounts Order, P. 6.
3 EB-2013-0321 Payment Amounts Order, P. 7.
4 Col. (a) 2017 Actual Production (Previously Regulated Hydroelectric) for June to December for 2017.
Col. (b) 2015 Actual Production (Previously Regulated Hydroelectric) of 19.3 TWh divided by 12 months multiplied by 2 months.
5 Col. (a) 2017 Actual Production (Newly Regulated Hydroelectric) for June to December for 2017.
Col. (b) 2015 Actual Production (Newly Regulated Hydroelectric) of 10.9 TWh divided by 12 months multiplied by 2 months.
6 2015 Actual Production of 30.2 TWh (sum of 19.3 TWh and 10.9 TWh) divided by 12 months multiplied by 36 months.
Per OPG PAO Cover Letter, calculation of revenue shortfall rider is based on pro-rating the 2015 actual regulated hydroelectric production.

Table 2
Nuclear Interim Period Shortfall Recovery Rider (Nuclear Payment Rider B)

Line No.	Description	Note	2017	2018
			(a)	(b)
	REVENUE SHORTFALL - JUNE 1, 2017 to FEBRUARY 28, 2018			
1	**Approved Payment Amount ($/MWh)**	1	80.65	83.10
2	**Interim Payment Amount ($/MWh)**	2	59.29	59.29
3	**Payment Amount Increase ($/MWh)**		21.36	23.81
	(line 1 - line 2)			
4	**Actual Production (TWh)**	3	24.8	7.2
5	**Revenue Shortfall June 1, 2017 to February 28, 2018 ($M)**		**529.0**	**171.6**
	(line 3 * line 4)			
	APPROVED PRODUCTION FORECAST - JANUARY 1, 2019 to DECEMBER 31, 2031			
6	**Total Forecast Production January 1, 2019 - December 31, 2021 (TWh)**	4		**111.8**
	NUCLEAR PAYMENT RIDER B:			
7	**Nuclear Payment Rider B Effective January 1, 2019 ($/MWh)**			**6.27**
	(sum of line 5 / line 6)			

Notes:

1 PAO App. C, Table 1, line 3.
2 EB-2013-0321 Payment Amounts Order, P. 8.
3 2017 Actual Production for June to December for 2017 and 2018 forecast production per Ex. E2-1-1 Table 2 for January 1, 2018 to implementation date of March 1, 2018.
4 2019 - 2021 OEB Approved Forecast Production per PAO App. C, Table 1. Sum of nuclear production forecast from 2019 to 2021 (line 2, col. (c) + col. (d) + col. (e)).
Per OPG PAO Cover Letter, calculation of revenue shortfall rider is based on nuclear forecast production.

Appendix G: Clearance and Continuation of Existing Deferral and Variance Accounts

CLEARANCE OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

With respect to the deferral and variance accounts established by *Ontario Regulation 53/05* ("O. Reg. 53/05") and the OEB's decisions and orders in EB-2007-0905, EB-2009-0174, EB-2010-0008, EB-2011-0090, EB-2012-0002, EB-2013-0321, EB-2014-0369, EB-2014-0370 and EB-2015-0374 the OEB approves:

1) A disposition debit amount of $86.8M (Appendix D, Table 1, col (h), line 12) for this proceeding from regulated hydroelectric deferral and variance accounts, reflecting OPG's approved recovery of the applicable audited December 31, 2015 balances in deferral and variance accounts (Appendix D, Table 1, col (a)) less amortization amounts for 2016 approved in EB-2014-0370 (Appendix D, Table 1, col (b)); and

2) A disposition debit amount of $217.9M (Appendix E, Table 1, col (h), line 16) for this proceeding from nuclear deferral and variance accounts, reflecting OPG's approved recovery of the applicable audited December 31, 2015 balances in deferral and variance accounts (Appendix E, Table 1, col (a)), less amortization amounts for 2016 approved in EB-2014-0370 (Appendix E, Table 1, col (b)).

The amounts approved for recovery will be amortized on a straight-line basis over the period from January 1, 2019 to December 31, 2021 as provided in Appendix D, Table 1, columns (e), (f) and (g) for the Regulated Hydroelectric Facilities and in Appendix E, Table 1, columns (e), (f), and (g) for the Nuclear Facilities.

The OEB approves OPG's recovery of the above approved balances in the regulated hydroelectric deferral and variance accounts using a payment rider of $0.96/MWh (Hydroelectric Payment Rider A), as determined in Appendix D Table 1, col (h), line 14.

The OEB approves OPG's recovery of the above approved balances in the nuclear deferral and variance accounts using a payment rider of $1.95/MWh (Nuclear Payment Rider A), as determined in Appendix E Table 1, col (h), line 18.

OPG shall continue to record entries into the deferral and variance accounts established by O. Reg. 53/05, and the EB-2013-0321 and EB-2014-0370 Payment Amount Orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and the above orders until the effective date of June 1, 2017 of this Payment Amount Order.

CONTINUING DEFERRAL AND VARIANCE ACCOUNTS

Unless otherwise stated in this Order, as of the effective date of the payment amounts established in this proceeding, OPG shall continue to record entries in the deferral and variance accounts authorized by O. Reg. 53/05 and the applicable decisions and orders of the OEB pursuant to the methodologies established by O. Reg. 53/05 and such decisions and orders, as set out below.

All references to the "regulated hydroelectric facilities" or "prescribed hydroelectric facilities" shall mean the 54 OPG hydroelectric generation stations subject to OEB rate regulation, as specified in O. Reg. 53/05. These facilities consist of five generation stations in OPG's Niagara Operations (Sir Adam Beck I and Sir Adam Beck II generating stations, Sir Adam Beck Pump Generating Station and DeCew Falls I and DeCew Falls II generating stations) and the R.H. Saunders generating station, all of which have been subject to rate regulation by the OEB since 2008 ("previously regulated hydroelectric facilities"), and the 48 hydroelectric generation stations that became subject to OEB rate regulation effective July 1, 2014 ("newly regulated hydroelectric facilities").

<u>Hydroelectric Water Conditions Variance Account</u>

The Hydroelectric Water Conditions Variance Account was originally established by O. Reg. 53/05 and has been approved in EB-2007-0905 and all subsequent OPG applications. This account shall continue to record the financial impact of changes in water conditions for the regulated hydroelectric facilities.

This account records the financial impact of differences, including changes in gross revenue charge ("GRC") costs, between actual production values for the regulated hydroelectric facilities and the reference production values, arising from changes in actual water conditions.

For the previously regulated hydroelectric facilities, OPG will continue to determine the hydroelectric production impact of changes in water conditions by entering the actual flow values into the same production forecast models used to calculate the OEB-approved production forecast, holding all other variables constant. OPG shall continue to use the average of the monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts as the reference values against which to measure production variances due to changes in water conditions arising for the corresponding months.

For the newly regulated hydroelectric facilities, 21 of 48 facilities listed in Ex. H1-1-1, Attachment 3 use computer models to forecast production. The models convert forecast water availability to monthly energy production forecasts using historical median monthly flows. Similar to the previously regulated hydroelectric facilities, for these 21 facilities, OPG shall continue to compute deviations of actual monthly flows from historical median monthly flows in order to determine the production variance. In calculating deviations from forecast for January 1 to June 30 of each year, OPG shall use the corresponding monthly production forecasts for 2015 underpinning the EB-2013-0321 payment amounts. In calculating such deviations for July 1 to December 31 of each year, OPG shall use the average of the corresponding monthly production forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts.

The revenue impact of the production variance recorded in the account will continue to be determined by multiplying the deviation from forecast, as described above, by the approved hydroelectric payment amount in effect during the relevant time period for these facilities. OPG shall also record in this account changes in the GRC costs by multiplying the production deviation as described above by the applicable GRC rates.

OPG shall also record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal as well as any variances from the amounts payable to the Government of Quebec for water rentals that were reflected in the revenue requirement approved by the OEB in EB-2013-0321.

Ancillary Services Net Revenue Variance Account

The Ancillary Services Net Revenue Variance Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. The account shall continue to be divided into the Ancillary Services Net Revenue Variance Account – Hydroelectric, and Ancillary Services Net Revenue Variance Account – Nuclear sub-accounts.

Ancillary services from regulated hydroelectric facilities include black start capability, operating reserve, regulation service (formerly referred to as automatic generation control), and reactive support/voltage control service. Ancillary services from nuclear facilities include reactive support/voltage control service.

To determine additions in this account for the regulated hydroelectric facilities, OPG shall compare actual regulated hydroelectric ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the OEB (the “reference amount”). The monthly reference amount shall be 1/12 of the average annual 2014 and 2015 forecast underpinning the revenue requirement approved by the OEB in EB-2013-0321. The resulting monthly reference amount shall be $4.62M[1]. The difference shall be recorded in the Ancillary Services Net Revenue Variance Account – Hydroelectric sub-account.

To determine additions to this account for the nuclear facilities, OPG shall compare actual nuclear ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the OEB. The monthly reference amount shall be 1/12 of the corresponding annual forecast revenue requirement approved by the OEB in this proceeding. Such annual amounts are $1.8M for 2017, $1.8M for 2018, $1.9M for 2019, $1.9M for 2020 and $2.0M for 2021[2]. The resulting monthly reference amounts shall be $0.15M for 2017, $0.15M for 2018, $0.16M for 2019, $0.16M for 2020 and $0.17M for 2021. The difference shall be recorded in the Ancillary Services Net Revenue Variance Account – Nuclear sub-account.

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[1] 1/12 of the sum of EB-2016-0152 Ex. H1-1-1, Table 3, lines 1 and 4.
[2] EB-2016-0152 Ex. G2-1-1 Table 1, line 8.

Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. OPG shall continue to record in the variance account a credit to ratepayers equal to 50% of its total regulated hydroelectric incentive mechanism net revenues above the annual threshold of $54.5M. This threshold reflects the average of the 2014 annual threshold of $51M and the 2015 threshold of $58M approved in EB-2013-0321.

Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications.

This account shall continue to record the financial impact of foregone production at the previously regulated hydroelectric facilities and the 21 newly regulated hydroelectric facilities listed in EB-2016-0152 Ex. H1-1-1 Attachment 3 due to surplus baseload generation (“SBG”) conditions.

OPG shall determine the revenue impact of SBG conditions by multiplying the foregone production volume by the approved regulated hydroelectric payment amount in effect, net of the avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates.

As described in EB-2013-0321, Ex. E1-2-1, section 3.2, OPG shall continue to calculate foregone production due to SBG conditions by starting with the total volume of spill at the regulated hydroelectric stations and subtracting the volume of spill due to factors such as:

- water conveyance constraints (e.g., Sir Adam Beck Generating Station tunnel capacity constraints);
- production capability constraints (e.g., unit outages, operating regulatory requirements);
- market constraints (i.e., IESO dispatch constraints); and
- contractual obligations (e.g., regulation service).

The remaining spill volume is identified as potential SBG spill. From this volume, OPG excludes spill that occurs when the Ontario market price is above the level of the GRC. The volume of spill remaining after this adjustment is the foregone production due to SBG conditions that is used to record entries in this account.

OPG shall also record in this account any variations, as a result of forgone production due to SBG conditions, in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal as well as any variances from the amounts payable to the Government of Quebec for water rentals reflected in the revenue requirement approved by the OEB in EB-2013-0321.

Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account shall continue to record the financial impact on the revenue requirement approved by the OEB of the following, with the exception of the impact of any of the following as it relates to Scientific Research and Experimental Development investment tax credits ("SR&ED ITCs") and the income taxes payable thereon, which will be recorded in the new SR&ED ITC Variance Account described in the accounting order in Appendix H:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (formerly the *Corporations Tax Act* (Ontario)), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*;
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and

- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

The income tax provision and the underlying inputs reflected in the revenue requirement approved by the OEB shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account (the "reference amount"). The reference amounts to be used in determining variances for the regulated hydroelectric facilities are those reflected in the average 2014 and 2015 income tax provision approved by the OEB in EB-2013-0321 and shown in the Payment Amounts Order Appendix A, Table 7 and Table 8 of that proceeding, as adjusted for the removal of the application of the nuclear facilities' tax loss to the regulated hydroelectric facilities in 2015. The resulting monthly reference amount for the regulated hydroelectric facilities shall be $6.52M, or 1/24 of the adjusted total income tax provision for 2014 and 2015 of $156.4M.[3]

The reference amount to be used in determining variances for the nuclear facilities shall be the corresponding annual income tax provision reflected in the nuclear revenue requirement approved by the OEB in this proceeding, as calculated in Appendix A, Tables 16-20, col. (c), line 26. The monthly reference amount for the nuclear facilities shall be ($1.53M) for each year from 2017 to 2021, being 1/12 of the annual amount of ($18.4M) reflected in the approved revenue requirements for 2017-2021.

Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account ("CRVA") was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account shall continue to record the financial impact of variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in O. Reg. 53/05 s. 2 and

[3] Calculated as the sum of: 2014 Income Taxes for Previously and Newly Regulated Hydroelectric Facilities of $47.4M and $21.4 respectively (EB-2013-0321 Payment Amounts Order, Appendix A line 23 col. (c) of Tables 1 and 2 respectively) and 2015 Income Taxes of $53.2M and $34.4M for Previously and Newly Regulated Hydroelectric Facilities respectively (EB-2016-0152 Ex. I1-2-1 Table 2a, col (a) and (b), line 14)

those forecast costs and firm financial commitments for projects reflected in the revenue requirement approved by the OEB (the "reference amount"). This account shall continue to include assessment costs and pre-engineering costs and commitments as required by O. Reg. 53/05 s. 6(2)4. In 2015, O. Reg. 53/05 was amended to affirm that the scope of this account includes the capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Program ("DRP").

Beginning the effective date of the 2017 approved hydroelectric payment amounts for the regulated hydroelectric facilities, the CRVA will record entries relative to the annual reference amount of $0.9M reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321[4]. Commencing on the effective date of the 2017 hydroelectric payment amount, OPG shall be entitled to recover amounts recorded in the account in relation to the regulated hydroelectric facilities to the extent that OPG's total capital in-service additions for these facilities exceed the funding available for capital expenditures calculated as set out in EB-2013-0321 per EB-2016-0152 Ex. H1-1-2 Table 3, col. (a). The annual CRVA capital funding implicit in the approved hydroelectric payment amounts shall be $143.3M (the "funding amount"), being the annual average of the depreciation expense for the regulated hydroelectric facilities reflected in the revenue requirement approved by the OEB for 2014 and 2015 in EB-2013-0321[5]. Both the reference amount and the funding amount will be escalated annually by the approved price cap index applied to increase hydroelectric payment amounts approved by the OEB.

For the nuclear facilities, this account shall continue to record entries relative to the reference amounts reflected in the annual revenue requirement approved by the OEB in this proceeding for each year from 2017 to 2021.

<u>Pension and OPEB Cost Variance Account</u>

The Pension and OPEB Cost Variance Account was originally approved in EB-2011-0090 and was continued in subsequent proceedings. This account records the difference between (i) the

[4] For 2017 the reference amount shall be the proportion of the annual reference amount of $0.9M from the approved effective date of hydroelectric payments amounts in 2017 to December 31, 2017

[5] For 2017 the funding amount shall be the proportion of the annual funding amount of $143.3M from the approved effective date of hydroelectric payment amounts in 2017 to December 31, 2017

pension and other post employment benefits ("OPEB") costs, plus related income tax PILs, reflected in the revenue requirement approved by the OEB (the "reference amount"), and (ii) OPG's actual pension and OPEB costs, and associated income tax impacts, for the previously regulated hydroelectric and nuclear prescribed generation facilities. Actual pension and OPEB costs used in the calculation of the difference are calculated on an accrual basis using the same accounting standards as those used to derive the reference amount.

In EB-2012-0002, the approved December 31, 2012 balance in the Pension and OPEB Cost Variance Account was split into the Historic Recovery and Future Recovery components. In EB-2013-0321, a third component was identified, which comprised additions recorded in the account subsequent to December 31, 2012 and up to November 1, 2014 (Post-2012 Additions). As at December 31, 2014, the Historic Recovery component was fully amortized. OPG shall continue to track the Future Recovery and the Post-2012 Additions components separately.

The Future Recovery component (for both regulated hydroelectric and nuclear facilities) was previously authorized by the OEB to be recovered over the period to December 31, 2024, and the Post-2012 Additions to June 30, 2021.

OPG shall not record any interest on the balance of this account as ordered by the OEB in EB-2013-0321 and EB-2014-0370.

<u>Hydroelectric Deferral and Variance Over/Under Recovery Variance Account</u>

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications.

This account shall continue to record the differences between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered based on actual regulated hydroelectric production and approved riders. The account shall also include the transfer of the regulated hydroelectric balances in accounts as they expire from time to time.

Gross Revenue Charge Variance Account

The Gross Revenue Charge Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account will continue to record the cost impact of a gross revenue charge reduction under Ontario Regulation 124/02, once approved by the Ontario Ministry of Natural Resources and Forestry, pertaining to production increases at OPG's Sir Adam Beck plants due to the operation of the new Niagara tunnel. The impact, if any, shall be determined by applying the approved reduction to the forecast gross revenue charge costs included in the hydroelectric revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321, averaged as applicable, holding all other variables constant. The impact shall be calculated as of the later of November 1, 2014 and the effective date of the approved gross revenue charge reduction.

Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account was approved in EB-2013-0321 and continued in EB-2014-0370. The account will continue to record the difference between OPG's actual registered pension plan contributions ("RPP") and OPEB plan payments (including the long-term disability benefit plan) attributed to the prescribed generating facilities, and such forecast amounts reflected in the revenue requirement approved by the OEB (the "reference amount").

With respect to the regulated hydroelectric facilities, the monthly reference amount for OPG's RPP contributions will be 1/12 of the average annual forecast of $45.1M[6] reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321. The resulting monthly reference amount shall be $3.76M. For OPG's OPEB payments, the monthly reference amount for the regulated hydroelectric facilities will be 1/12 of the annual average forecast of $12.8M[7] reflected in the revenue requirement for 2014 and 2015 approved by the OEB in EB-2013-0321. The resulting monthly reference amount shall be $1.07M.

With respect to the nuclear facilities, the monthly reference amount for OPG's RPP contributions will be 1/12 of $200.0M, $202.9M, $243.5M, $247.9M, and $250.6M[8] for each respective year

[6] EB-2016-0152 Ex. H1-1-1, Table 8, col. (a), line 1
[7] EB-2016-0152 Ex. H1-1-1, Table 8, col. (a), line 2
[8] PAO, Appendix A, Tables 16 to 20, col. (c), line 15 for 2017 to 2021 respectively

from 2017 to 2021, as reflected in the nuclear revenue requirement approved by the OEB in this proceeding. The resulting monthly reference amount shall be $16.67M, $16.91M, $20.29M, $20.66M and $20.88M for each respective year from 2017 to 2021. The monthly reference amount for OPG's OPEB plan payments will be 1/12 of $91.1M, $95.7M, $99.9M, $104.3M, and $108.5M[9] for each respective year from 2017 to 2021, as reflected in the nuclear revenue requirement approved by the OEB in this proceeding. The resulting monthly reference amount shall be $7.59M, $7.98M, $8.33M, $8.69M and $9.04M for each respective year from 2017 to 2021.

OPG shall continue to separately track amounts recorded in this variance account for the regulated hydroelectric and nuclear prescribed assets.

Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was approved in EB-2013-0321 and continued in EB-2014-0370. This account will continue to record differences between (i) OPG's actual pension and OPEB costs for its prescribed generating facilities determined using the accrual accounting method applied in OPG's audited consolidated financial statements, and (ii) OPG's actual RPP contributions and OPEB plan payments (including the long-term disability benefit plan) attributed to OPG's prescribed generating facilities.

OPG shall continue to separately track amounts recorded in this variance account for the regulated hydroelectric and nuclear prescribed assets. No interest shall be recorded on the balance of this account, consistent with the EB-2013-0321 and EB-2014-0370 Payment Amounts Orders.

Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was approved in EB-2014-0369, effective November 1, 2014.

[9] PAO, Appendix A, Tables 16 to 20, col (c), line 16 for 2017 to 2021 respectively

The account shall continue to record the difference between the annual revenue requirement impact of the Niagara Tunnel Project rate base addition disallowance of $28.0 million ordered in EB-2013-0321 and the varied disallowance of $6.4 million determined in EB-2014-0369. The payment amounts for the regulated hydroelectric facilities approved in this proceeding reflect the EB-2013-0321 disallowance and do not reflect the impact of the varied disallowance.

Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account shall continue to record the revenue requirement impact on the prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities ("nuclear liabilities") arising from an approved reference plan under the Ontario Nuclear Funds Agreement measured against the forecast impact reflected in the revenue requirement approved by the OEB. OPG shall not record the revenue requirement impact of a change in its nuclear liabilities related to the Bruce facilities in this account. OPG shall record the return on rate base in the account using the weighted average accretion rate on OPG's nuclear liabilities of 4.95%[10].

O. Reg. 53/05 defines the "nuclear decommissioning liability" as "the liability of Ontario Power Generation Inc. for decommissioning its nuclear generating facilities and the management of its nuclear waste and nuclear fuel." An "approved reference plan" shall be defined as "a reference plan, as defined in the Ontario Nuclear Funds Agreement, which has been approved by Her Majesty the Queen in the right of Ontario in accordance with that agreement."

OPG shall not record any interest on the balance of the Nuclear Liability Deferral Account.

Nuclear Development Variance Account

The Nuclear Development Variance Account was originally approved in EB-2007-0905 pursuant to O. Reg. 53/05 and has been approved in all subsequent OPG applications. This account shall continue to record variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed

[10] PAO App A, Tables 11 – 15, line 7, col. (c)

new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the OEB (the “reference amount”). The monthly reference amount shall be $0.19M, $0.12M, $0.14M, $0.15M and $0.15M for each respective year from 2017 to 2021, being 1/12 of the corresponding annual amounts of $2.3M, $1.4M, $1.7M, $1.8M and $1.8M reflected in the approved revenue requirement for 2017-2021[11].

Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications.

This account will continue to have two sub-accounts as follows:

Derivative Sub-Account

The derivative sub-account balance relates to the previously existing derivative liability for the conditional supplemental rent rebate provision of the Bruce lease (including associated income tax impacts on Bruce lease net revenues calculated in accordance with generally accepted accounting principles for unregulated entities) and the rent rebates associated with supplemental rent revenue.

Pursuant to the 2015 amendment to the Bruce lease agreement, the provision for a conditional supplemental rent rebate was removed effective December 4, 2015 and the derivative liability has been eliminated. The remaining balance in the account is a credit balance that largely represents the amount that the had OEB authorized prior to the 2015 amendment to the agreement, to be recovered for the Bruce Derivative for the post-December 3, 2015 period through the EB-2014-0370 rate riders. As a result of the 2015 amendment to the agreement, this recovery is no longer required and will be refunded to ratepayers. As a result, no further derivative related amounts will be recorded and this sub-account shall only record interest and amortization.

[11] EB-2016-0152 Ex. F2-1-1 Table 1, line 6, plus amounts provided in Note 1 to that table

Non-Derivative Sub-Account

The non-derivative sub-account balance relates to the non-derivative aspects of the account, including the cost impact of any changes in OPG's liability for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations.

The variance recorded in the non-derivative sub-account shall be determined by comparing (i) the quotient of the annual forecast amount of ($5.2M), ($7.3M), ($20.6M), ($20.1) and ($40.4M) reflected in the revenue requirement approved by the OEB for each respective year from 2017 to 2021[12] and the approved nuclear production forecast for the corresponding year of 38.1 TWh, 38.5 TWh, 39.0 TWh, 37.4 TWh and 35.4 TWh for each respective year from 2017 to 2021[13] ("rate of recovery") multiplied by OPG's actual nuclear production from 2017 to 2021, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities. The rate of recovery shall be ($0.137)/MWh in 2017, ($0.19)/MWh in 2018, ($0.528)/MWh in 2019, ($0.537)/MWh in 2020, and ($1.141)/MWh in 2021.

Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account was originally approved in EB-2009-0174 and has been approved in all subsequent OPG applications.

This account shall continue to record the differences between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered based on actual nuclear production and approved riders. The account shall also include the transfer of the nuclear portion of other variance and deferral accounts as they expire from time to time.

Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral Account

The Impact Resulting from Changes in Station End-of-Life Dates (December 31 2015) Deferral Account was approved in EB-2015-0374. This account records the revenue requirement impact arising from changes to nuclear liabilities and depreciation and amortization expense resulting

[12] PAO, Appendix A, Tables 1 to 5 line 20 for 2017 to 2021 respectively
[13] PAO, Appendix I, Table 2, line 6p

from changes to station end-of-life dates for Bruce, Pickering and Darlington nuclear generating stations that became effective December 31, 2015.

Pursuant to the EB-2015-0374 Decision and Order, the account additions were to continue until the effective date of this payment amounts order. As such, no further additions are to be recorded to the account as of the effective date of the 2017 nuclear payment amount established in this proceeding.

No interest shall be recorded on the balance of this account consistent with the EB-2015-0374 Payment Amounts Order.

INTEREST

Except where otherwise stated as of the effective date of the payment amounts established in the proceeding, OPG shall record interest on the balances in all deferral and variance accounts using the interest rates set by the OEB from time to time pursuant to the OEB's interest rate policy. Unless stated otherwise, OPG shall apply simple interest to the opening monthly balance of the accounts until the balances are fully recovered or refunded.

Rate Smoothing Deferral Account

Ontario Power Generation Inc.

Illustrative Accounting Order

Basis of Approval

O. Reg. 53/05 section 5.5; EB-2016-0152 Decision and Order, Pages 116-117 and 155.

Scope of Account

Effective January 1, 2017, OPG shall establish the Rate Smoothing Deferral Account in accordance with section 5.5 of O. Reg. 53/05. This account shall record, for each respective year, the difference between: (i) the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB; and, (ii) the portion of that revenue requirement in (i) that is used in connection with setting the approved nuclear payment amounts in each year ("the annual deferral amount"). The annual deferral amount shall be ($62M)[1], ($164M), $144M, $602M, and $213M for each respective year from 2017-2021, to be recorded monthly on a straight-line basis.[2]

OPG shall record the annual deferral amount in the account as follows:

Entry	Debit	Credit
DR/CR Rate Smoothing Deferral Account	xx,xxx	xx,xxx
CR/DR Revenue	xx,xxx	xx,xxx

To record the difference between the total annual revenue requirement for the prescribed nuclear facilities approved by the OEB and the portion of that revenue requirement that is used in connection with setting the approved nuclear payment amounts in each year.

[1] A $0 deferral amount applies for January 1, 2017 to May 31, 2017 as the previous, unsmoothed payment amount was in effect for production during that period. The June 1, 2017 to December 31, 2017 deferral amount of ($62M) is calculated using production weighting on the 2017 nuclear production forecast that reflects the effective date of June 1, 2017 for the smoothed payment amounts established in this Order.
[2] Appendix C, Table 1, line 5

Per O. Reg. 53/05, s. 5.5 (2), the deferral account shall record interest on the balance at the following OEB-approved long-term debt rates reflecting OPG's cost of long-term borrowing, compounded annually: 4.89% for 2017, 4.60% for 2018, 4.52% for 2019, 4.49% for 2020, and 4.48% for 2021.[3]

O. Reg. 53/05 requires recovery of the account balance on a straight line basis, beginning upon the end of the Darlington Refurbishment Project, over a period of 10 years or less.

[3] Appendix A, Tables 11 through 15, col. (c), line 2.

Fitness for Duty Deferral Account
Ontario Power Generation Inc.
Illustrative Accounting Order

Basis of Approval

EB-2016-0152 Decision and Order, Pages 57 and 118.

Scope of Account

Effective June 1, 2017, OPG shall establish the Fitness for Duty Deferral Account. The account shall record the costs related to implementing the Canadian Nuclear Safety Commission ("CNSC") Fitness for Duty program. The Fitness for Duty program is a drug, alcohol, psychological and physical testing program for employees in nuclear facilities, anticipated to be a license requirement of the CNSC.

Entry	Debit	Credit
DR Fitness for Duty Deferral Account	xx,xxx	
CR OM&A Expenses		xx,xxx

To record the costs related to implementing the Fitness for Duty Program.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered.

SR&ED ITC Variance Account

Ontario Power Generation Inc.

Illustrative Accounting Order

Basis of Approval

EB-2016-0152 Decision and Order, Pages 88 and 113.

Scope of Account

Effective June 1, 2017, the SR&ED ITC Variance Account will record the tax expense impact for the nuclear facilities as a result of the difference between actual SR&ED ITCs (attributed to the nuclear facilities) as determined after any tax audits and the forecast SR&ED ITCs included in the nuclear revenue requirement approved by the OEB. The forecast SR&ED ITCs included in the approved revenue requirements for the 2017-2021 period are $18.4M per year[4] or $1.53M per month.

Entry	Debit	Credit
DR/CR Income Tax Expense	xx,xxx	xx,xxx
CR/DR SR&ED ITC Variance Account	xx,xxx	xx,xxx

To record the tax expense impact of the difference between SR&ED ITCs included in the approved nuclear revenue requirement and actual SR&ED ITCs.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

[4] PAO Appendix A Tables 16 to 20, col (c), line 25.

Hydroelectric Interim Period Shortfall (Hydroelectric Payment Rider B) Over/Under Recovery Variance Account

Ontario Power Generation Inc.

Illustrative Accounting Order

Basis of Approval

EB-2016-0152 Decision and Order, Page 156; EB-2007-0905 Payment Amounts Order, Appendix F, Page 7.

Scope of Account

The scope of this account is consistent with the OEB's approval of a variance account to implement recovery of hydroelectric interim period shortfall amounts determined in EB-2007-0905 in a manner that would keep customers and OPG whole. This variance account shall record the difference between the approved amount of regulated hydroelectric revenue foregone for the period from the approved effective date of the 2017 hydroelectric payment amount to the implementation date of the 2018 hydroelectric payment amount (the “Hydroelectric Shortfall”), and the Hydroelectric Payment Rider B amounts recovered in the period from January 1, 2019 to December 31, 2021 based on actual regulated hydroelectric production.

Entry	Debit	Credit
DR/CR Revenue	xx,xxx	xx,xxx
CR/DR Hydroelectric Interim Period Shortfall (Hydroelectric Payment Rider B) Over/Under Recovery Variance Account	xx,xxx	xx,xxx

To record the variance between the approved amount of the Hydroelectric Shortfall and the amount recovered from customers based on actual regulated hydroelectric production and Hydroelectric Payment Rider B.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

Nuclear Interim Period Shortfall (Nuclear Payment Rider B) Over/Under Recovery Variance Account

Ontario Power Generation Inc.

Illustrative Accounting Order

Basis of Approval

EB-2016-0152 Decision and Order, Page 156; EB-2007-0905 Payment Amounts Order Appendix F, Page 7.

Scope of Account

The scope of this account is consistent with the OEB's approval of a variance account to implement recovery of nuclear interim period shortfall amounts determined in EB-2007-0905 in a manner that would keep customers and OPG whole. This variance account shall record the difference between the approved amount of nuclear revenue foregone for the period from the approved effective date of the 2017 nuclear payment amount to the implementation date of the 2018 nuclear payment amount (the “Nuclear Shortfall”), and the Nuclear Payment Rider B amounts recovered in the period from January 1, 2019 to December 31, 2021 based on actual nuclear production.

Entry	Debit	Credit
DR/CR Revenue	xx,xxx	xx,xxx
CR/DR Nuclear Interim Period Shortfall (Nuclear Payment Rider B) Over/Under Recovery Variance Account	xx,xxx	xx,xxx

To record the variance between the approved amount of the Nuclear Shortfall and the amount recovered from customers based on actual nuclear production and Nuclear Payment Rider B.

OPG shall record simple interest on the monthly opening balance in this account in accordance with the OEB's prescribed interest rate for deferral and variance accounts until the balances are fully recovered or refunded.

APPENDIX I – RATE SMOOTHING PROPOSAL

1.0 PURPOSE AND OVERVIEW

This appendix sets out a revised rate smoothing proposal, pursuant to the OEB's Decision and Order in this proceeding, dated December 28, 2017 (the "Decision") and the requirements of O. Reg. 53/05 (the "Regulation").

- Section 2.0 summarizes the revised rate smoothing proposal at a high level, in the context of the prior proposals filed by OPG in this proceeding.
- Section 3.0 reviews the OEB's findings on rate smoothing in the Decision.[1]
- Section 4.0 reviews the rate smoothing requirements in the Regulation. This section is largely identical to corresponding material in Ex. N3-1-1. It is included in this appendix for ease of reference.
- Section 5.0 describes the inputs into the calculation of the weighted average payment amounts ("WAPA"), interim period shortfall riders, and the combined customer bill impact of both WAPA and shortfall riders.
- Section 6.0 sets out OPG's current proposal, including the company's assessment of how the proposal satisfies the rate smoothing principles as accepted and refined by the OEB in the Decision.

The Decision requires OPG to provide alternative rate smoothing scenarios reflecting three different implementation dates (March 1, 2018 April 1, 2018 and May 1, 2018). OPG has provided analyses for each implementation date in the Tables accompanying this appendix.[2] OPG's proposal and the figures that appear in this narrative section of the appendix are based on a March 1, 2018 implementation date, which OPG believes to be achievable.

[1] Decision, p. 152.
[2] The tables are provided in three sets. Tables 1-2 reflect an implementation date of March 1, 2018; Table 3 reflects an implementation date of April 1, 2018; and Table 4 reflects an implementation date of May 1, 2018.

2.0 SUMMARY OF RATE SMOOTHING PROPOSALS

OPG's rate smoothing proposal was initially set out in Ex. A1-3-3 of the pre-filed evidence, based on the requirements of the Regulation then in effect. In that proposal, OPG had contemplated increasing nuclear payment amounts by 11% per year, from 2017 through 2021 (the "IR Term"). OPG forecasted that the proposal would have resulted in average annual increases of approximately $1.05 for residential customers' monthly bills during the IR Term, with a total interest cost of approximately $1.4 billion over the deferral and recovery period to 2036.[3]

The Regulation was subsequently amended on March 2, 2017, introducing the requirement that the OEB determine deferral amounts with a view to making OPG's WAPA more stable.[4] OPG prepared a revised rate smoothing proposal in accordance with the amended regulation, which was filed as Ex. N3-1-1 on March 8, 2017. OPG forecasted that the revised approach would result in average annual increases of approximately $0.65 for residential customers' bills during the IR Term, again with a total interest cost of approximately $1.4 billion over the deferral and recovery period.

In written submissions, OPG, OEB staff, and other parties suggested that the OEB defer its final decision on rate smoothing until the payment amounts process. The OEB accepted these suggestions, and provided guidance on the appropriate approach to rate smoothing (the OEB's guidance is discussed in section 3.0 below).[5]

Based on the OEB's guidance in the Decision, OPG has further revised its proposal as set out in this appendix ("current proposal"). The current proposal reflects the adjustments made to proposed revenue requirement arising from the Decision, as well as the effective and implementation dates resulting from the Decision. OPG forecasts that the current proposal would result in annual increases of approximately $0.65[6] or 0.4% for residential customers' monthly bills during the IR Term, with a total interest cost of approximately $1.1 billion (Chart 6, p. 17) over the deferral and recovery period. As described in section 6.5,

[3] Ex. N3-1-1, p. 11, Chart 3.
[4] Ex. N3-1-1, p. 1.
[5] Decision, p. 155.
[6] PAO Appendix I Table 1.

OPG estimates that medium/large and industrial customers' monthly bills would increase by an average of approximately 0.5% annually.[7]

Based on the guidance in the Decision, OPG has adjusted the methodology underlying the proposed rate smoothing approach in two ways. First, it has allowed the annual change in WAPA to vary between years. Second, OPG has considered the total bill impact of the smoothing proposal (including both WAPA and the impact of interim period shortfall riders) when calculating the proposed annual deferral amounts. Together, these methodological changes have allowed OPG to design a rate smoothing approach that targets a consistent $0.65 year-over-year change in residential customers' monthly bills, while satisfying the requirement in O. Reg. 53/05 that WAPA be "more stable" during the IR Term.

OPG proposes to defer implementation of new deferral and variance account and interim period shortfall payment riders until January 1, 2019. Delaying the implementation of riders will help minimize the customer bill impact of new payment amounts in 2018.

Major outcomes of the three proposals are as follows:

[7] PAO Appendix I, Tables 1b through 1c, line 7

	Smoothing Approach	**Major Outcomes**		
		Average Annual Bill Increase[8]*	Total Interest Cost*	Total Deferrals During IR Term*
Initial Proposal	• 11% annual increase in nuclear payment amounts	$1.05	$1.4 billion	$1.6 billion
Revised Proposal	• Constant 2.5% annual increase in WAPA	$0.65	$1.4 billion	$1.0 billion
Current Proposal	• Some variability in the year-over-year WAPA • Deferral amounts reflect customer bill impact of interim period shortfall recovery payment riders; • Defer implementation of payment amount riders until 2019	$0.65	$1.1 billion	$0.7 billion

*Approximate values. Bill impacts reflect year-over-year increases for a typical residential customer's monthly bill

Based on the analysis set out in the sections below, OPG believes that the current proposal delivers value for customers. Following the guidance in the Decision, OPG proposes variable changes in WAPA, and to smooth customer bills by adjusting the recovery periods for riders established in this proceeding. The resulting proposal continues to produce moderate, consistent annual bill impacts, at a total carrying cost that is approximately $300M less than the prior proposal.

[8] For residential customers. Bill impacts for other customer classes are discussed in section 6.4.

3.0 OEB DECISION

In the Decision, the OEB approved the Rate Smoothing Deferral Account ("RSDA") effective January 1, 2017.[9] The OEB also determined that it would consider rate smoothing as part of the payment amounts order process, taking the outcomes of the Decision into account.[10]

The OEB also agreed that the six guiding principles that OPG used to develop its rate smoothing proposals are appropriate, subject to refinements related to the Rate Stability and Customer Bill Impact considerations, as follows:[11]

Rate Stability:
Although rate stability is an important principle, it is not necessary that OPG's WAPA change at a constant year-over-year rate. OPG may propose a constant increase, if it concludes that such an approach would best satisfy the Regulation and the principles of the Renewed Regulatory Framework.[12]

Customer Bill Impact:
The impact on customers' bills is also an important consideration, and rate smoothing proposals should consider the impact of rate smoothing on multiple classes of customers (including but not limited to residential customers).[13]
Rate smoothing proposals should seek to avoid "rate shock" in the first year of the IR Term.[14] Although none of the proposals put forward by OPG have crossed the OEB's formal threshold for rate mitigation (10% impact on customer bills), OPG understands that the OEB expects rate smoothing proposals to consider impacts on customers' bills at the beginning of the period.
The Decision requires OPG to propose a recovery period for payment amount riders including an analysis of customer bill impacts.[15] From this finding, OPG understands

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[9] Decision, p. 117.
[10] Decision, p. 155.
[11] Decision, p. 155.
[12] Decision, p. 155.
[13] Decision, p. 155.
[14] Decision, p. 155.
[15] Decision, p. 156.

that the OEB expects the company's rate smoothing proposal to consider the total bill impact on customers, including interim period shortfall riders.

While the Decision does not prescribe specific mechanics of rate smoothing, it reaffirms that, although the Regulation sets out broad parameters for rate smoothing, the OEB retains discretion to determine the mechanics, including how much of OPG's approved nuclear revenue requirement to defer.[16]

OPG has considered the requirements of the Regulation and the OEB's refinements to the rate smoothing principles and reflected them in the current proposal, as described below in section 6.0.

4.0 REQUIREMENTS OF O. REG. 53/05

For ease of reference, this section summarizes the rate smoothing requirements prescribed by the Regulation. The content of this section is consistent with the corresponding section in Ex. N3-1-1.

O. Reg. 53/05, s. 6(2) subparagraph 12(i) states:

> "the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), **with a view to making more stable the year-over-year changes in the OPG weighted average payment amount** [WAPA] **over each calculation period**." [emphasis added]

The calculation of WAPA is described in section 4.1 below.

The "**calculation period**" is defined in s. 0.1(1) of the Regulation as:

> "each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period"

[16] Decision, p. 155.

Subparagraph 12(ii) of subsection 6(2) of the Regulation requires that the OEB determine nuclear revenue requirements and amounts to be deferred on a five-year basis for the first 10 years of the deferral period (2017-2026).

4.1 Calculation of Weighted Average Payment Amount (WAPA)

Section 0.1(1) of the Regulation defines OPG's WAPA for a year through the following formula:

$$\frac{((NPA + NPR) \times NPF) + ((HPA + HPR) \times HPF))}{(NPF + HPF)}$$

NPA (**Nuclear Payment Amount**) is the Board-approved payment amount for the year in respect of the nuclear facilities

NPR (**Nuclear Payment Riders**) is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the RSDA

NPF (**Nuclear Production Forecast**) is the Board-approved production forecast for the nuclear facilities for the year

HPA (**Hydroelectric Payment Amount**) is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the [prescribed] hydroelectric facilities

HPR (**Hydroelectric Payment Riders**) is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities

HPF (**Hydroelectric Production Forecast**) is the Board-approved production forecast for the hydroelectric facilities for the year

The NPR, NPF, HPA, and HPR are collectively referred to as the "inputs" in this appendix, since they are the values that the OEB must approve in this Order to determine the annual amounts of nuclear revenue requirement to be recorded in the RSDA for the 2017-2021 period. While the NPA is also approved by the OEB, it is an output (rather than an input) of the prescribed formula since it will reflect the annual deferral of nuclear revenue requirement. As described in section 5.0 below, HPF reflects the average annual hydroelectric production forecast approved by the OEB in EB-2013-0321.

5.0 INPUTS TO RATE SMOOTHING

This section identifies the values for the inputs required to determine annual deferral amounts to be recorded in the RSDA during the IR Term.

As described in Ex. N3-1-1, each of the following steps is necessary in order to determine the amounts to be deferred in the RSDA:

Step	Action	Basis in O. Reg. 53/05
1	Establish the RSDA	s. 5.5(1)
2	Approve annual nuclear revenue requirements for the five-year IR Term, absent any deferral	s. 5.5(1)(a) s. 6(2)12(ii) s. 6(2)12(iii)
3	Approve required WAPA inputs for each year	
4	Determine the annual change in the WAPA, applying the principles approved by the OEB in the Decision (including impact on customer bills) to assess options with a view to making more stable the year-over-year changes in the WAPA over each calculation period (“Smoothed WAPA Rate”)	s. 0.1(1) s. 6(2)12(i)
5	Using the Smoothed WAPA Rate determined in Step 4 and the inputs approved in Step 3, determine the annual NPA	s. 0.1(1)
6	Determine annual deferred amount to be recorded in RSDA for each year of the five year term [Step 2 - (NPA x NPF)]	s. 5.5(1)(b) s. 6(2)12(i)

The nuclear revenue requirements and nuclear production forecasts (NPF) approved for the IR Term by the OEB are summarized in Chart 1 below.

Chart 1: Nuclear Revenue Requirements and Production[17]

	2017	2018	2019	2020	2021
Approved Revenue Requirement ($M)	$ 2,973	$ 3,032	$ 3,116	$ 3,579	$ 3,174
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38

Hydroelectric Payment Amount (HPA): Pursuant to the Regulation, OPG has calculated WAPA using the approved 2017 HPA of $41.67/MWh and the approved 2018 HPA of $42.05/MWh. For the purpose of WAPA smoothing, OPG has calculated proxy payment amounts for 2019, 2020 and 2021 by escalating the approved HPA for 2018 of $42.05/MWh by the 2018 price cap index value of 0.9% (Appendix B, Table 1, Line 6), yielding $42.43/MWh in 2019, $42.81/MWh in 2020 and $43.20/MWh in 2021 (Appendix B, Table 1, Line 6). Actual hydroelectric payment amounts for 2019, 2020 and 2021 will be set in subsequent applications.

Nuclear Payment Rider (NPR) and Hydroelectric Payment Rider (HPR): To help mitigate bill impacts, OPG proposes that no hydroelectric or nuclear payment riders for the recovery of deferral and variance accounts be established for 2018. OPG proposes that such riders, for recovery of December 31, 2015 deferral and variance account balances, be implemented on January 1, 2019, continuing through December 31, 2021. Based on the OEB's approvals in the Decision, the proposed hydroelectric and nuclear payment riders for those years are $0.96/MWh[18] and $1.95/MWh[19], respectively.

The rate smoothing proposal does not reflect payment riders for recovery of deferral and variance account balances after December 31, 2015, as none are proposed in this Application. Any payment riders the OEB may establish for those account balances would be separate from the rate smoothing proposal and would not affect the revenue requirement deferral amounts approved by the OEB in this proceeding. In a subsequent proceeding, the OEB could assess the future bill impact of potential payment riders for recovery (or refund) of any amounts approved.

Determination of Annual Change in WAPA: Pursuant to the Regulation, the calculation period in this Application is 2016-2021. OPG calculates WAPA for each year in the calculation

[17] Chart 1 is consistent with the presentation in Ex. A1-3-3 Chart 1 and Ex. N3-1-1 Chart 1.
[18] PAO Appendix D Table 1.
[19] PAO Appendix E Table 1.

period as demonstrated in Appendix I Table 2. It is a requirement of the Regulation that a rate smoothing proposal result in WAPA that is more stable than would be the case without deferral of nuclear revenue requirement.[20]

Total OPG Regulated Production: Per the Regulation, OPG arrived at the 2016 weighted average payment amount using the average of the 2014 and 2015 OEB approved production.[21] For 2017 onward, OPG has utilized the approved nuclear production forecast[22] and the average of the 2014 and 2015 OEB approved hydroelectric production.[23]

5.1 Post-2021 Projections used in Smoothing Analysis

As described in Ex. N3-1-1, an understanding of forecast nuclear costs and production for the entire deferral and recovery period is necessary context to determine the appropriate rate smoothing proposal under the Regulation.[24] While it is not possible to forecast revenue requirement and production out 20 years with a high degree of accuracy, Chart 2 reproduces OPG's view of the approximate longer-term nuclear revenue requirements and production, along with indicative average nuclear rates that would result for the 2022 to 2036 period without smoothing, in nominal dollars.

Chart 2: Nuclear Revenue Requirement, Production and Average Unsmoothed Rate[25]

	2017-2021	2022-2026	2027-2031	2032-2036
Revenue Requirement ($BN)	$ 15.9	$ 18.1	$ 18.2	$ 17.1
Production (TWh)	188	130	136	141
Average Rate ($/MWh)	$ 84	$ 139	$ 135	$ 121

[20] O. Reg. 53/05, s. 6 (2)(12)(i); relative to WAPA as defined in s. 0.1 (1).
[21] PAO Appendix I Table 2 Note 3.
[22] PAO Appendix I Table 2, Line 6.
[23] 33 TWh, per EB-2013-0321, Decision with Reasons, p. 9.
[24] As discussed in Ex. A1-3-3 and Ex. N3-1-1, rate smoothing is primarily driven by variations in nuclear costs and production during the deferral period. Therefore, the rate smoothing analysis is based on stable hydroelectric production and hydroelectric payment amount escalation at 0.9% per year throughout the deferral and recovery periods (as a proxy for actual hydroelectric payment amounts to be determined by the OEB in the future, consistent with the description in section 5.0).
[25] Chart 2 is consistent with the presentation in Ex. A1-3-3 Chart 2 and Ex. N3-1-1 Chart 2.

The Regulation requires the OEB to authorize recovery of the balance in the RSDA over a period not to exceed ten years.[26] As the magnitude of the costs being deferred is in the billions of dollars, OPG's smoothing proposal continues to assume that the RSDA balance is recovered over the maximum ten-year period.

5.2 Interim Period Shortfall Recovery Payment Riders

Consistent with the Decision and as discussed in section 6.0 below, OPG has considered the bill impact of interim period shortfall recovery riders in developing its current rate smoothing proposal. The values used for these riders are shown in Appendix F, Tables 1 and 2, for regulated hydroelectric and nuclear facilities respectively, under a March 1, 2018 implementation date. To mitigate customer bill impact in 2018, OPG proposes that the interim period shortfall recovery riders commence in 2019.

5.3 Customer Bill Impact Calculation

OPG has determined the annualized residential consumer impact on a basis that is consistent with both previous OEB proceedings and with the approach taken in the pre-filed evidence (including Ex. N3-1-1). The calculation of the annualized impact reflects the approvals set out in the Decision and their impact on 2017 to 2021 nuclear revenue requirement. The annualized residential customer impact is determined by multiplying the year-over-year change in WAPA[27] by the proportion of a typical residential customer's consumption in the year that OPG production comprises.[28] Appendix I Table 1 provides the computation of these impacts for 2017 through 2021 under a March 1, 2018 implementation date.

OPG used the inputs described below to calculate the residential consumer impacts, consistent with the pre-filed evidence (including Ex. N3-1-1):

> **Typical residential consumption**: 789 kWh, based on the typical monthly consumption (750 kWh) used in the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), increased to include line losses (using an

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[26] O. Reg. 53/05 section 6 (2), subparagraph 12 (iv).
[27] PAO Appendix I, Table 1, line 8.
[28] PAO Appendix I, Table 1, line 2.

assumed loss factor of 1.0525). The "Bill Calculator" is available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility.

Typical residential bill: $150.58 is taken from the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing). OPG runs this bill calculator tool for all local distribution companies available in the bill calculator and uses a simple average of all of the bills as the typical bill.

Forecast of 2017 Provincial Demand: Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published on March 22, 2016.

As requested in the Decision, OPG has also estimated bill impacts for typical medium and large business customers, and typical large industrial customers. Appendix I Tables 1B, 1C, and 1D show estimated bill impacts for these customer classes in the Alectra PowerStream rate zone, Hydro One Networks Inc., and Toronto Hydro-Electric System Limited service territories, respectively, under a March 1, 2018 implementation date.

6.0 PROPOSAL

Pursuant to the guidance provided in the Decision, OPG has revised its approach to rate smoothing in two respects:

1. Rather than setting a constant year-over-year change in WAPA for the IR Term, the current proposal allows WAPA to fluctuate year-over-year in order to reduce annual variability in customer bills, including the impact of interim period shortfall recovery riders.

2. OPG has proposed deferral amounts that mitigate bill impacts during the IR Term that would otherwise be caused by interim period shortfall recovery riders, in addition to meeting the legislative requirement of a "more stable" WAPA.

OPG's previous rate smoothing proposal was based solely on annual RSDA deferral amounts producing a consistent 2.5% year-over-year change in WAPA. As defined under the

Regulation, WAPA does not include the impact of interim period shortfall recovery riders.[29] As a result, rate smoothing based on a constant year-over-year change in WAPA could still produce variable bill impacts due to the implementation and expiry of shortfall riders during the IR Term.

6.1 Implementation Date

OPG proposes a March 1, 2018 implementation date. OPG believes that this implementation date is achievable and produces better outcomes for customers. A later date would necessarily result in a greater interim period shortfall amount, which, in turn, would result in either larger customer bill impacts or larger deferral amounts and associated carrying costs.

OPG has calculated bill impacts that would result from different implementation dates (March 1, 2018, April 1, 2018 and May 1, 2018) while maintaining a constant $0.65 year-over-year residential customer bill impact, assuming that all proposed riders end by December 31, 2021. These scenarios are presented in Appendix I Table 1 (March 1), Table 3 (April 1) and Table 4 (May 1).

6.2 Smoothing based on Total Payments

OPG's proposed WAPA is shown in Chart 3. OPG has calculated year-over-year changes in WAPA that offset the implementation of interim period shortfall recovery riders that would otherwise cause greater annual variability in customers' bills. As shown in Chart 3, this proposal produces year-over-year changes in "total payments" (i.e., WAPA combined with the impact of interim period shortfall recovery riders) averaging 2.5%.

[29] Interim period shortfall recovery riders are not an input to WAPA since they are necessarily a product of the RSDA deferral amounts and smoothed nuclear payment amounts that the OEB approves in the context of rate smoothing.

Chart 3: WAPA and Total Payments

	2016	2017	2018	2019	2020	2021
Annual Amount $						
Unsmoothed WAPA (Unconstrained Payment Amounts)	$ 60.97	$ 61.16	$ 61.85	$ 64.21	$ 72.45	$ 68.74
Smoothed WAPA (Determines RSDA Deferral Amounts)	$ 60.97	$ 62.57	$ 64.15	$ 62.22	$ 63.89	$ 65.62
Total Payments (Smoothed WAPA combined with impact of shoftfall riders)	$ 60.97	$ 62.57	$ 64.15	$ 65.72	$ 67.33	$ 68.98
% Change in Annual Amounts						
Unsmoothed WAPA (Unconstrained Payment Amounts)		0.3%	1.1%	3.8%	12.8%	-5.1%
Smoothed WAPA (Determines RSDA Deferral Amounts)		2.6%	2.5%	-3.0%	2.7%	2.7%
Total Payments (Smoothed WAPA combined with impact of shoftfall riders)		2.6%	2.5%	2.4%	2.4%	2.5%

This proposal satisfies the requirement that WAPA be made “more stable” than would otherwise be the case during the IR Term. While the proposed WAPA (“smoothed WAPA”) is more variable than in OPG’s prior approach, it is significantly less variable than the WAPA that would result from unconstrained payment amounts (“unsmoothed WAPA”).

Under this proposal, both smoothed WAPA and total payments are significantly less volatile than the unsmoothed WAPA during the IR Term. The average change of the proposed smoothed WAPA amounts is 2.7% over the IR Term[30], which is significantly more stable than the 4.6% average change of the unsmoothed WAPA in the same period[31]. The resulting total payments are even more stable, with an almost constant rate of change of 2.5% in each year of the IR Term.

As in previous proposals and as required by the Regulation, deferrals recorded in the RSDA are to be based on the “smoothed WAPA.”

6.3 Payment Amounts and Annual Deferred Revenue Requirement

OPG’s proposal results in deferring the collection of approximately $700M in revenue in the 2017 to 2021 period, as reflected in Chart 4 below. This is approximately $300M less than OPG proposed to defer under the previous proposal, and $900M less than in the initial rate smoothing proposal.

[30] Change in annual absolute values (2.6% + 2.5% + 3.0% + 2.7% + 2.7%) / 5 years = 2.7%
[31] Change in annual absolute values (0.3% + 1.1% + 3.8% + 12.8% + 5.1%) / 5 years = 4.6%

Chart 4 also reflects the proposed, smoothed nuclear payment amounts that result in the level of deferred recovery associated with the current proposal.

Chart 4: Proposed Nuclear Payment Amounts and Deferred Revenue Requirement[32,33]

	2017	2018	2019	2020	2021	Total
Unconstrained Nuclear Payment Amount ($M)	$ 78.03	$ 78.82	$ 79.86	$ 95.81	$ 89.70	N/A
Revenue Requirement ($M)	$ 2,973	$ 3,032	$ 3,116	$ 3,579	$ 3,174	$ 15,875
Production (TWh)	38.10	38.47	39.03	37.36	35.38	188.33
Smoothed Nuclear Payment Amount ($/MWh)	$ 80.65	$ 83.10	$ 76.17	$ 79.70	$ 83.67	N/A
Smoothed Revenue ($M)	$ 3,073	$ 3,197	$ 2,973	$ 2,977	$ 2,961	$ 15,180
Deferred Revenue Requirement ($M)	$ (62)	$ (165)	$ 144	$ 602	$ 213	$ 732

6.4 Customer Bill Impacts

As shown in Chart 5, OPG's revised rate smoothing approach produces a consistent $0.65 year-over-year residential bill increase for each year of the IR Term, including the impact of shortfall riders proposed for 2019-2021. The bill impact of the current proposal in the IR Term is unchanged from the average annual bill impact identified in OPG's previous proposal.[34]

Chart 5: Proposed Customer Bill Impacts[35]

	2017	2018	2019	2020	2021
Residential Customer Bill Impact $	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65
Residential Customer Bill Impact %	0.4%	0.4%	0.4%	0.4%	0.4%

Chart 5 is based on detailed calculations set out in Appendix I Table 1.

[32] A $0 deferral amount would apply for January 1, 2017 to May 31, 2017, recognizing that the previous, unsmoothed nuclear payment amount is in effect for production during that period. The ($62M) deferral amount for June 1, 2017 to December 31, 2017 is calculated using the 2017 proposed smoothed payment amount of $80.65/MWh (PAO Appendix C, Table 1, line 3, col. (a)) and a production weighting (on the NPF) that reflects the approved effective date of June 1, 2017.
[33] Chart 4 is consistent with the presentation in Ex. A1-3-3 Chart 4 and Ex. N3-1-1 Chart 4, with the addition of unconstrained (i.e. unsmoothed) nuclear payment amounts for reference.
[34] Ex. N3-1-1, Chart 3.
[35] Chart 5 does not compare the impact of interim rates in 2017 and early 2018 with the proposed total payments for those years, as that comparison is not relevant to the determination of WAPA pursuant to the Regulation. However, if the smoothed payment amounts proposed to be effective March 1, 2018 are compared to the actual payment amounts in effect as of December 31, 2016, the result is a residential customer bill increase of $1.30 over two years, or an average of $0.65 per year . This is consistent with the annual bill impacts shown in Chart 5.

Consistent with the Regulation and other charts in this appendix, Chart 5 presents customer bill impacts on an annual basis. The 2017 column reflects the bill impact for a typical residential customer in that year, comparing proposed 2017 total payments (as per Chart 3) to OEB-approved 2016 payment amounts and riders. The 2018 column compares proposed total payments for 2018 to those for 2017, and so on.

As shown in Appendix I Tables 1B, 1C, and 1D, the bill impact on medium, large, and industrial customers is moderate. Across the three service territories reviewed, the average year-over-year monthly bill impact for typical medium/large and industrial customers is an increase of approximately 0.5%.[36]

As noted above, OPG has proposed that neither interim period shortfall riders nor deferral and variance account riders be implemented until 2019, and that they be recovered over a three-year period from 2019 to 2021. OPG expects that customers will benefit from a delayed implementation of riders and a longer recovery period.

6.5 Application of Rate Smoothing Principles

Chart 6 summarizes other major elements of the revised rate smoothing proposal. For reference, Chart 6 also includes OPG's previous proposal as provided in Ex. N3-1-1.

Since the OEB is not approving payment amounts or RSDA deferral amounts beyond 2021 in this Application, Chart 6 includes illustrative trends for OPG's WAPA and the average year-over-year change in a typical residential customer's monthly bill throughout the 20-year deferral and recovery period. Chart 6 also includes the approximate peak RSDA account balance, the estimated credit metrics associated with each option, and the final smoothed rate at the end of the recovery period. As with the scenarios originally presented in Ex. A1-3-3 Chart 3 and Ex. N3-1-1 Chart 3, the actual trajectory of payment amounts will depend on the OEB's decisions throughout the remainder of the deferral and recovery periods.

[36] Line 7 of PAO Appendix I Tables 1B, 1C and 1D shows the approximate percentage bill increase for medium/large and industrial customers. As the OEB suggested on page 156 of the Decision, OPG has used the same methodology to prepare these tables as was used to prepare Ex. J20.1.

Chart 6: Outcomes of Rate Smoothing Proposal[37,38]

	Prior Proposal (Ex. N3-1-1)	Current Proposal
2017-2021 Average Change in WAPA	2.5%	2.7%
2022-2026 Average Change in WAPA	7.0%	8.0%
2027-2036 Average Change in WAPA	(1.0)%	(1.5)%
Peak RSDA Balance ($B)	$2.9	$2.7
Total Interest ($BN)	$1.4	$1.1
Interest Cost / Deferred Revenue Ratio	0.5	0.4
FFO Interest Coverage > = 3 (2017-2021) & (2022-2026)	4.6 / 5.4	4.3 / 4.6
DEBT to EBITDA < = 5.5 (2017-2021) & (2022-2026)	5.9 / 5.2	6.5 / 5.4
Nuclear Payment Amount Transition Impact ($/MWh)	($3.70)	($0.19)
Average Annual Bill Impact (2017-2021) in %	0.4%	0.4%
Average Annual Bill Impact (2017-2021) in $	$0.65	$0.65
Average Annual Bill Impact (2017-2036) in %[1]	0.3%	0.3%
Average Annual Bill Impact (2017-2036) in $[1]	$0.47	$0.45

[37] Chart 6 is consistent with the presentation in Ex. A1-3-3 Chart 3 and Ex. N3-1-1 Chart 3.
[38] For comparability with the prior proposal, the estimated Debt to EBITDA ratio shown in Chart 6 assumes a January 1, 2017 effective date for the new payment amounts. Under a June 1, 2017 effective date, the ratio would be unfavourably impacted relative to the value shown.

In OPG's assessment, the proposal satisfies each of the six rate smoothing principles endorsed by the OEB:

Financial Viability (Leverage and Cash Flow Impacts): Higher values for the FFO Adjusted Interest Coverage ratio and lower values for the Debt to EBITDA credit metric reduce financial risk to OPG. OPG's assessment was based on at least one of the two metrics cited above being within threshold at all times during each of the two 5-year deferral periods (i.e., 2017 to 2021 and 2022 to 2026). The current proposal meets this threshold.

Rate Stability: The current proposal results in annual changes in WAPA that are considerably more stable than the unsmoothed WAPA. As discussed in section 6.2, the proposal results in year-over-year changes in WAPA that are significantly less volatile than unsmoothed WAPA, and total payments with an almost constant rate of change in each year of the IR Term. In OPG's view, the proposal satisfies the Regulation and the rate stability principle.

Long-Term Perspective: The assessment was based on the size of the average year-over-year change in WAPA during the recovery period (closer to 0% is better). At an average annual WAPA decrease of 1.5% during the recovery period, the proposal performs well on this measure.

Post-Recovery Transition: The assessment was based on the size of the change in the nuclear payment amount at the end of the recovery period (smaller is better) to the forecast post-transition payment amount of approximately $120/MWh. With an estimated transition impact of approximately $0.20/MWh, the proposal performs very well on this measure.

Intergenerational Equity: The assessment was based on the ratio of total interest costs to total amounts deferred (total interest / total amounts deferred). A lower ratio implies a lower cost of deferring revenue under that alternative. Intergenerational equity involves striking a balance between the benefits of deferring revenue and the costs of the deferral; therefore OPG's assessment placed value on a ratio that best reflects this balance. The proposal results in lower interest costs and peak account balances than the prior proposal. The proposal performs well on this measure, with a ratio that is comparable (if slightly lower) than the prior proposal.

Customer Bill Impact: OPG believes that the proposal delivers value for customers, particularly on this measure. The proposal results in a consistent year-over-year increase of $0.65 for a typical residential customer's monthly bill during the IR Term.[39] As discussed in section 6.4, the average year-over-year impact on typical medium/large and industrial customers' monthly bills is an increase of approximately 0.5%.

The proposal was based on smoothed WAPA calculated to produce a consistent, moderate customer bill impact in each year of the IR Term, including the impact of interim period shortfall riders. OPG has incorporated the OEB's guidance in the Decision, proposing to moderate bill impacts by delaying implementation of payment riders, and a three-year recovery period.

[39] Although interim payment amounts have been lower since January 1, 2017 due to the expiry of deferral and variance account riders at the end of 2016, when proposed payment amounts to be implemented in 2018 are compared to the actual payment amounts in effect as of December 31, 2016, the result is a residential customer bill increase of $1.30, or an average of $0.65 per year.

Table 1
Annualized Residential Consumer Impact - March 1, 2018 Payment Amount Implementation Date
January 1, 2017 to December 31, 2021

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
1	**Typical Consumption (kWh/Month)**	1	789	789	789	789	789
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)		408	410	413	403	392
3	**Typical Bill ($/Month)**	1	150.58	150.58	150.58	150.58	150.58
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)		**0.65**	**0.65**	**0.65**	**0.65**	**0.65**
5	**Typical Bill Impact (%)** (line 4 / line 3)		**0.4%**	**0.4%**	**0.4%**	**0.4%**	**0.4%**
6	Prior Year OPG Weighted Average Total Payments ($/MWh)	2	60.97	62.56	64.15	65.72	67.33
7	Current Year OPG Weighted Average Total Payments ($/MWh)	2	62.56	64.15	65.72	67.33	68.98
8	Change in OPG Weighted Average Total Payments ($/MWh) (line 7 - line 6)		1.59	1.59	1.56	1.61	1.65
9	Total OPG Regulated Production (TWh)	3	71.1	71.4	72.0	70.3	68.4
10	Forecast of 2017 Provincial Demand (TWh)	4	137.6	137.6	137.6	137.6	137.6
11	OPG Proportion of Consumer Usage (line 9 / line 10)		51.7%	51.9%	52.3%	51.1%	49.7%

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: https://www.oeb.ca/consumer-protection/energy-contracts/bill-calculator
Typical Consumption includes line losses (Assumed loss factor of 1.0525).

2 PAO App. I, Table 2, line 11.

3 PAO App. I, Table 2, line 3 and line 6.

4 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

Numbers may not add due to rounding.

Table 1b

Annualized Bill Impact for Typical Alectra (PowerStream) Consumers 2017-2021 - Implementation Date of March 1, 2018

Line No.	Description	Note	2017 Medium/Large Business	2017 Large Industrial	2018 Medium/Large Business	2018 Large Industrial	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)**		42,748	1,496,182	42,972	1,504,021	43,306	1,515,713	42,301	1,480,541	41,115	1,439,034
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	14,157	467,845	14,157	467,845	14,157	467,845	14,157	467,845	14,157	467,845
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	1.59	1.59	1.59	1.59	1.56	1.56	1.61	1.61	1.65	1.65
7	**Percentage Increase in Consumer Bills**		0.48%	0.51%	0.48%	0.51%	0.48%	0.51%	0.48%	0.51%	0.48%	0.51%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		68.11	2,383.85	68.28	2,389.66	67.75	2,371.17	68.08	2,382.91	67.80	2,373.05

Notes:

1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Powerstream EB-2015-0003 Draft Rate Order.
Medium/Large Business (EB-2015-0003 Draft Rate Order, Schedule B, Page 4): GS > 50 customer, consumption 80,000 kWh, loss factor 3.45%.
Large Industrial (EB-2015-0003 Draft Rate Order, Schedule B, Page 5): Large User customer, consumption 2,800,000 kWh, loss factor 3.45%.

2 Per PAO App. I, Table 2, line 3 and line 6.

3 Per PAO App. I, Table 1, line 11.

4 Per PAO App. I, Table 1, line 8.

Numbers may not add due to rounding.

Table 1c
Annualized Bill Impact for Typical Hydro One Networks Consumers 2017-2021 - Implementation Date of March 1, 2018

Line No.	Description	Note	2017 Medium/Large Business	2017 Large Industrial	2018 Medium/Large Business	2018 Large Industrial	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	37,135	517,000	37,135	517,000	37,135	517,000	37,135	517,000	37,135	517,000
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)**		19,181	267,046	19,282	268,445	19,432	270,532	18,981	264,255	18,449	256,846
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	6,435	68,653	6,435	68,653	6,435	68,653	6,435	68,653	6,435	68,653
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	1.59	1.59	1.59	1.59	1.56	1.56	1.61	1.61	1.65	1.65
7	**Percentage Increase in Consumer Bills**		0.47%	0.62%	0.48%	0.62%	0.47%	0.62%	0.47%	0.62%	0.47%	0.62%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		30.56	425.48	30.64	426.52	30.40	423.22	30.55	425.31	30.42	423.55

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Hydro One EB-2013-0416 Draft Rate Order.
Medium/Large Business (EB-2013-0416 Draft Rate Order, Exhibit 7): GSd customer, consumption 35,000 kWh, loss factor 6.1%.
Large Industrial (EB-2013-0416 Draft Rate Order, Exhibit 7): ST customer, consumption 500,000 kWh, loss factor 3.4%.
2 Per PAO App. I, Table 2, line 3 and line 6.
3 Per PAO App. I, Table 1, line 11.
4 Per PAO App. I, Table 1, line 8.

Numbers may not add due to rounding.

Table 1d
Annualized Bill Impact for Typical Toronto Hydro Consumers 2017-2021 - Implementation Date of March 1, 2018

Line No.	Description	Note	2017 Medium/Large Business	2017 Large Industrial	2018 Medium/Large Business	2018 Large Industrial	2019 Medium/Large Business	2019 Large Industrial	2020 Medium/Large Business	2020 Large Industrial	2021 Medium/Large Business	2021 Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)**		80,393	2,367,854	80,814	2,380,259	81,442	2,398,763	79,552	2,343,100	77,322	2,277,411
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	27,003	771,057	27,003	771,057	27,003	771,057	27,003	771,057	27,003	771,057
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in OPG Weighted Average Total Payments ($/MWh)**	4	1.59	1.59	1.59	1.59	1.56	1.56	1.61	1.61	1.65	1.65
7	**Percentage Increase in Consumer Bills**		0.47%	0.49%	0.48%	0.49%	0.47%	0.49%	0.47%	0.49%	0.47%	0.49%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		128.09	3,772.67	128.40	3,781.87	127.41	3,752.61	128.04	3,771.18	127.51	3,755.59

Notes:
1 Current Approved Rates and Usage (adjusted for line losses) are taken from the THESL EB-2014-0116 Draft Rate Order
Medium/Large Business (EB-2014-0116 Draft Rate Order, Schedule 9, Page 7): GS 50-999 customer, consumption 150,000 kWh, loss factor 3.76%
Large Industrial (EB-2014-0116 Draft Rate Order, Schedule 9, Page 9): Large Use customer, consumption 4,500,000 kWh, loss factor 1.87%
2 Per PAO App. I, Table 2, line 3 and line 6.
3 Per PAO App. I, Table 1, line 11.
4 Per PAO App. I, Table 1, line 8.

Numbers may not add due to rounding.

Table 2

Computation of OPG Weighted Average Payment Amount and Total Payments - March 1, 2018 Payment Amounts Implementation Date

Line No.	Description	Note	2016 per EB-2013-0321 / EB-2014-0370 Payment Amounts Orders	2017 per EB-2016-0152 Payment Amounts Order	2018 per EB-2016-0152 Payment Amounts Order	2019 per EB-2016-0152 Payment Amounts Order	2020 per EB-2016-0152 Payment Amounts Order	2021 per EB-2016-0152 Payment Amounts Order
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Hydroelectric Payment Amount (HPA) ($/MWh)**	1	40.72	41.67	42.05	42.43	42.81	43.20
2	**Hydroelectrc Payment Rider (HPR) ($/MWh)**	2	3.83			0.96	0.96	0.96
3	**Hydroelectric Production Forecast (HPF) TWh**	3	33.0	33.0	33.0	33.0	33.0	33.0
4	**Nuclear Payment Amount (NPA) ($/MWh)**	4	59.29	80.65	83.10	76.17	79.70	83.67
5	**Nuclear Payment Rider (NPR) ($/MWh)**	5	13.01			1.95	1.95	1.95
6	**Nuclear Production Forecast (NPF) TWh**	6	47.8	38.10	38.5	39.0	37.4	35.4
7	**Weighted Average Payment Amount ($/MWh)** **(((NPA + NPR) x NPF) + (HPA + HPR) x HPF) / (NPF + HPF)**		60.97	62.57	64.15	62.22	63.89	65.62
8	**Percentage Change in Weighted Average Payment Amount (Year over Year)**			2.6%	2.5%	-3.0%	2.7%	2.7%
9	**Hydroelectric Interim Period Shortfall Recovery Rider (HSR) ($/MWh)**	7	0.00	0.00	0.00	0.23	0.23	0.23
10	**Nuclear Interim Period Shortfall Recovery Rider (NSR) ($/MWh)**	8	0.00	0.00	0.00	6.27	6.27	6.27
11	**Weighted Average Total Payments ($/MWh)** **(((NPA + NPR + NSR) x NPF) + (HPA + HPR + HSR) x HPF) / (NPF + HPF)**		60.97	62.56	64.15	65.72	67.33	68.98
12	**Percentage Change in Weighted Average Total Payments (Year over Year)**			2.6%	2.5%	2.4%	2.4%	2.4%

Notes

1 Col. (a) is average Regulated Hydroelectric payment amount for July to December 2015 (production-weighted average of previously and newly regulated hydroelectric payment amounts in effect at the end of 2015). See Ex. I1-2-1 Table 1(a), col. (a).
Col. (b) to (c) are OEB approved hydroelectric payment amounts per PAO App. B, Table 1, line 6.
Col. (d) to (f) is illustrative hydroelectric payment amounts per PAO App. B, Table 1, line 6.

2 Col. (a) are EB-2014-0370 approved hydroelectric riders in effect as of December 31, 2016.
Col. (d) to (f) are EB-2016-0152 approved hydroelectric riders per PAO App. D, Table 1, line 14.

3 Regulated Hydroelectric production is the 2014 and 2015 average OEB approved hydroelectric production per EB-2013-0321 Decision and Order P. 9.

4 Col. (a) is payment amount of $59.29/MWh (EB-2013-0321 Payment Amounts Order, Appendix D, Table 1, line 3).
Col. (b) to (f) is calculated as the OPG proposed payment amounts to arrive at the WAPA as described in PAO App. I, Section 6.3.

5 Col. (a) are EB-2014-0370 approved nuclear riders in effect as of December 31, 2016.
Col. (d) to (f) are EB-2016-0152 approved nuclear riders per PAO App. E, Table 1, line 18.

6 Col. (a) Nuclear 2016 production is the 2014 and 2015 average approved per EB-2013-0321 Decision and Order P. 39.
Col. (b) to (f) 2017-2021 from PAO App. C, Table 1, approved per OEB Decision and Order P. 12.

7 Regulated Hydroelectric interim period shortfall recovery rider per PAO App. F, Table 1, line 12.

8 Nuclear interim period shortfall recovery rider per PAO App. F, Table 2, line 7.

Table 3

Interim Period Shortfall Payment Riders, OPG Weighted Average Payment Amount and Residential Customer Impact - April 1 Payment Amounts Implementation Date

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	Weighted Average Payment Amount Inputs						
1	Nuclear Production Forecast (NPF) (TWh)	1	38.1	38.5	39.0	37.4	35.4
2	Nuclear Payment Rider (NPR) ($/MWh)	1			1.95	1.95	1.95
3	Hydroelectric Payment Amounts (HPA) ($/MWh)	1	41.67	42.05	42.43	42.81	43.20
4	Hydroelectric Production Forecast (HPF) (TWh)	1	33.0	33.0	33.0	33.0	33.0
5	Hydroelectric Payment Rider (HPR) ($/MWh)	1			0.96	0.96	0.96
	Weighted Average Payment Amount Outputs						
6	Weighted Average Payment Amount (WAPA) ($/MWh)	2	62.57	64.15	61.81	63.49	65.24
7	Nuclear Payment Amount (NPA) ($/MWh)	2	80.65	83.10	75.42	78.95	82.93
8	Nuclear Deferral Amount ($M)	2	(62)	(164)	173	630	239
	Interim Period Shortfall Payment Riders						
10	Hydroelectric Shortfall Production (TWh)	3	17.2	7.6			
11	Hydroelectric Interim Period Shortfall ($M)	3	14.9	9.3			
12	Hydroelectric Interim Period Shortfall Rider ($/MWh)	3			0.27	0.27	0.27
13	Nuclear Shortfall Production (TWh)	3	24.8	10.6			
14	Nuclear Interim Period Shortfall Rider ($M)	3	529	252			
15	Nuclear Interim Period Shortfall Rider ($/MWh)	3			6.99	6.99	6.99
	Residential Customer Bill Impact						
16	Typical Bill Impact ($/Month)	1	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65
17	Typical Bill Impact (%)	1	0.4%	0.4%	0.4%	0.4%	0.4%

Notes
1 Unchanged from OPG proposal reflecting a payment amounts implementation date of March 1, 2018.
2 Adjusted to reflect Interim Period Shortfall Recovery Riders based on an April 1, 2018 payment amounts implementation date and maintain a residential bill impact of $0.65 per year.
3 Adjusted to include March 2018 revenue shortfall using the same approach as for January and February 2018 at App. F, Tables 1 and 2.

Table 4

Interim Period Shortfall Payment Riders, OPG Weighted Average Payment Amount and Residential Customer Impact - May 1 Payment Amounts Implementation Date

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	Weighted Average Payment Amount Inputs						
1	Nuclear Production Forecast (NPF) (TWh)	1	38.1	38.5	39.0	37.4	35.4
2	Nuclear Payment Rider (NPR) ($/MWh)	1			1.95	1.95	1.95
3	Hydroelectric Payment Amounts (HPA) ($/MWh)	1	41.67	42.05	42.43	42.81	43.20
4	Hydroelectric Production Forecast (HPF) (TWh)	1	33.0	33.0	33.0	33.0	33.0
5	Hydroelectric Payment Rider (HPR) ($/MWh)	1			0.96	0.96	0.96
	Weighted Average Payment Amount Outputs						
6	Weighted Average Payment Amount (WAPA) ($/MWh)	2	62.57	64.15	61.49	63.18	64.93
7	Nuclear Payment Amount (NPA) ($/MWh)	2	80.65	83.10	74.83	78.36	82.34
8	Nuclear Deferral Amount ($M)	2	(62)	(164)	196	652	260
	Interim Period Shortfall Payment Riders						
10	Hydroelectric Shortfall Production (TWh)	3	17.2	10.1			
11	Hydroelectric Interim Period Shortfall ($M)	3	14.9	12.4			
12	Hydroelectric Interim Period Shortfall Rider ($/MWh)	3			0.30	0.30	0.30
13	Nuclear Shortfall Production (TWh)	3	24.8	13.2			
14	Nuclear Interim Period Shortfall Rider ($M)	3	529	315			
15	Nuclear Interim Period Shortfall Rider ($/MWh)	3			7.55	7.55	7.55
	Residential Customer Bill Impact						
16	Typical Bill Impact ($/Month)	1	$ 0.65	$ 0.65	$ 0.65	$ 0.65	$ 0.65
17	Typical Bill Impact (%)	1	0.4%	0.4%	0.4%	0.4%	0.4%

Notes
1 Unchanged from OPG proposal reflecting a payment amounts implementation date of March 1, 2018.
2 Adjusted to reflect Interim Period Shortfall Recovery Riders based on an May 1, 2018 payment amounts implementation date and maintain a residential bill impact of $0.65 per year.
3 Adjusted to include March 2018 revenue shortfall using the same approach as for January and February 2018 at App. F, Tables 1 and 2.