SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

EB-2016-0152

OPG Panel 5B

Numbers may not add due to rounding.

Table 1
D2-1-3 Table 4 Updated for 2016 Actuals
Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Darlington NGS	89.9	(10.0)	79.9	(48.8)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	Pickering NGS	53.6	41.3	94.9	(26.2)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	Nuclear Support Divisions[1]	17.4	10.2	27.6	(1.6)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	Subtotal	160.8	41.6	202.4	(76.7)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	Supplemental In-Service Forecast[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	Total Portfolio In-Service Forecast	160.8	41.6	202.4	(76.7)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	Minor Fixed Assets	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	Total In-Service Capital Additions	180.7	31.9	212.6	(64.0)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(e)-(a) Change	2016 Budget	(e)-(c) Change	2016 Actual	(g)-(e) Change	2017 Plan	(i)-(g) Change	2018 Plan	(k)-(i) Change	2019 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	Darlington NGS	107.0	112.8	331.4	(111.6)	219.8	(38.4)	181.3	(29.4)	152.0	10.4	162.4
10	Pickering NGS	71.7	(23.8)	164.9	(117.0)	47.9	38.1	86.0	(70.2)	15.8	(13.0)	2.8
11	Nuclear Support Divisions[1]	3.1	(1.3)	17.1	(15.3)	1.8	5.1	6.9	(3.3)	3.6	(3.6)	0.0
12	Subtotal	181.8	87.7	513.4	(243.9)	269.5	4.8	274.3	(102.9)	171.4	(6.2)	165.2
13	Supplemental In-Service Forecast[2]	0.0	0.0	(47.4)	47.4	0.0	88.7	88.7	35.1	123.8	(68.8)	55.0
14	Total Portfolio In-Service Forecast	181.8	87.7	466.0	(196.5)	269.5	93.5	363.0	(67.7)	295.2	(75.0)	220.2
15	Darlington New Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Minor Fixed Assets	22.3	0.2	31.0	(8.5)	22.5	3.5	26.0	(6.0)	20.0	(0.9)	19.1
17	Total In-Service Capital Additions	204.1	87.9	497.0	(205.0)	292.0	97.0	389.0	(73.7)	315.2	(75.9)	239.3

Line No.	Business Unit	2019 Plan	(c)-(a) Change	2020 Plan	(e)-(c) Change	2021 Plan
		(a)	(b)	(c)	(d)	(e)
18	Darlington NGS	162.4	(102.4)	60.0	(21.3)	38.7
19	Pickering NGS	2.8	(2.8)	0.0	0.0	0.0
20	Nuclear Support Divisions[1]	0.0	0.0	0.0	0.0	0.0
21	Subtotal	165.2	(105.3)	60.0	(21.3)	38.7
22	Supplemental In-Service Forecast[2]	55.0	150.7	205.7	(48.0)	157.6
23	Total Portfolio In-Service Forecast	220.2	45.4	265.6	(69.3)	196.3
24	Darlington New Fuel	0.0	15.3	15.3	(15.3)	0.0
25	Minor Fixed Assets	19.1	0.4	19.5	(0.1)	19.3
26	Total In-Service Capital Additions	239.3	61.1	300.4	(84.8)	215.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

Numbers may not add due to rounding.

Table 4

Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	89.9	(18.3)	71.5	(40.5)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	**Pickering NGS**	53.6	40.5	94.1	(25.4)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	**Nuclear Support Divisions**[1]	17.4	10.4	27.8	(1.8)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	**Subtotal**	160.8	32.6	193.5	(67.8)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	**Supplemental In-Service Forecast**[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	**Total Portfolio In-Service Forecast**	160.8	32.6	193.5	(67.8)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	**Minor Fixed Assets**	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	**Total In-Service Capital Additions**	180.7	23.0	203.7	(55.1)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Darlington NGS**	107.0	224.5	331.4	(150.1)	181.3	(29.4)	152.0	10.4	162.4	(102.4)	60.0
10	**Pickering NGS**	71.7	93.2	164.9	(78.9)	86.0	(70.2)	15.8	(13.0)	2.8	(2.8)	0.0
11	**Nuclear Support Divisions**[1]	3.1	13.9	17.1	(10.1)	6.9	(3.3)	3.6	(3.6)	0.0	0.0	0.0
12	**Subtotal**	181.8	331.6	513.4	(239.1)	274.3	(102.9)	171.4	(6.2)	165.2	(105.3)	60.0
13	**Supplemental In-Service Forecast**[2]	0.0	(47.4)	(47.4)	136.1	88.7	35.1	123.8	(68.8)	55.0	150.7	205.7
14	**Total Portfolio In-Service Forecast**	181.8	284.3	466.0	(103.0)	363.0	(67.7)	295.2	(75.0)	220.2	45.4	265.6
15	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	15.3
16	**Minor Fixed Assets**	22.3	8.7	31.0	(5.0)	26.0	(6.0)	20.0	(0.9)	19.1	0.4	19.5
17	**Total In-Service Capital Additions**	204.1	292.9	497.0	(108.0)	389.0	(73.7)	315.2	(75.9)	239.3	61.1	300.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
18	**Darlington NGS**	60.0	(21.3)	38.7
19	**Pickering NGS**	0.0	0.0	0.0
20	**Nuclear Support Divisions**[1]	0.0	0.0	0.0
21	**Subtotal**	60.0	(21.3)	38.7
22	**Supplemental In-Service Forecast**[2]	205.7	(48.0)	157.6
23	**Total Portfolio In-Service Forecast**	265.6	(69.3)	196.3
24	**Darlington New Fuel**	15.3	(15.3)	0.0
25	**Minor Fixed Assets**	19.5	(0.1)	19.3
26	**Total In-Service Capital Additions**	300.4	(84.8)	215.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

service amounts, and I believe we indicated that in the undertaking response that I understand has been filed, that some in-service amounts expected in 16 originally are going to happen in 2017, yes.

MS. KHOO: And correspondingly, does that mean some projects from 2017 might be pushed into 2018?

MR. KOGAN: I don't think I can comment. I was simply responding because I was familiar with that from reading the undertaking response. My understanding -- I think that's all I can say.

MS. KHOO: Okay. So if I were to also ask about forecasted delays for 2017 to 2018, would you be able to speak to that?

MR. KOGAN: No, we could not. It was not our intent, per the understanding of the undertaking, to reflect that.

MS. KHOO: Would I be able to ask you to reflect that in the undertaking?

MR. FRALICK: It's barely April into 2017, and the extent to which there has been some movement in Q1 we would know directionally. But it's quite early in the year for us to be forecasting shifts that varied from our most recent update through the spectrum of the rest of the proceeding. So I mean, we can look and see if there is anything material, but --

MS. KHOO: That would be great. Okay, that was --

MR. SMITH: We'll look for anything material.

MR. MILLAR: J 20.14.

UNDERTAKING NO. J20.14: WITH REFERENCE TO UNDERTAKING

AMPCO Interrogatory #16

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Ref: C1-1-1- Page 1

a) Please provide the annual impact on revenue requirement if the current capital structure is maintained.

Response

The annual impact on the Nuclear revenue requirement if the current capital structure is maintained is provided in Attachment 1.

See Ex L-1-9.8 Staff-217 for the expected entry into the Hydroelectric Capital Structure Variance Account.

Numbers may not add due to rounding.

Table 1
Calculation of Cost of Capital Using Current and Proposed Capital Structure ($M)

Line No.	Description	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)
1	**Nuclear Rate Base**[1]	3,344.4	3,513.9	3,449.8	7,494.0	7,959.1
2	**ROE**[2]	9.19%	9.19%	9.19%	9.19%	9.19%
3	**Cost of Debt**[2]	4.91%	4.63%	4.56%	4.52%	4.51%
4	**Deemed Equity (Proposed)**[2]	49%	49%	49%	49%	49%
5	**Deemed Debt (Proposed)**[2]	51%	51%	51%	51%	51%
6	**Proposed WACC**[3]	7.0%	6.9%	6.8%	6.8%	6.8%
7	**Deemed Equity (EB-2013-0321)**	45%	45%	45%	45%	45%
8	**Deemed Debt (EB-2013-0321)**	55%	55%	55%	55%	55%
9	**Proposed WACC (At EB-2013-0321 Capital Structure)**[4]	6.8%	6.7%	6.6%	6.6%	6.6%
10	**Revenue Requirement (Proposed)**[5]	284.5	293.9	287.4	622.7	660.8
11	**Revenue Requirement (At EB-2013-0321 Capital Structure)**[6]	274.6	283.2	276.7	599.5	636.1
12	**Revenue Requirement Impact if EB-2013-0321 Capital Structure is Maintained**[7]	**(9.8)**	**(10.7)**	**(10.6)**	**(23.2)**	**(24.7)**

Notes
1 Ex. B1-1-1 Table 2, line 7 minus the Adjustment for Lesser of UNL or ARC from Ex. C1-1-1 Tables 1-5, line 7
2 C1-1-1Tables 1-5
3 Calculated as: (Line 2 X Line 4) + (Line 3 X Line 5)
4 Calculated as: (Line 2 X Line 7) + (Line 3 X Line 8)
5 (Line 1 x Line 6) + (Line 1 x Line 2 x Line 4) x (tax rate / 1- tax rate), where the tax rate is 25%
6 (Line 1 x Line 9) + (Line 1 x Line 2 x Line 7) x (tax rate / 1- tax rate), where the tax rate is 25%
7 (Line 11 - Line 10)

period January 1, 2018 to December 31, 2021, entries into this account would record the annual nuclear revenue requirement impact of the difference between the OEB's annually updated prescribed ROE and the annual ROE incorporated into the 2018 to 2021 annual revenue requirements approved by the OEB. .

To facilitate calculating the annual nuclear revenue requirement impact of the difference, OPG proposes to multiply the difference in ROE in each of 2018 to 2021 by the forecast nuclear rate base financed by capital structure for each year in 2018 to 2021 that is approved by the OEB in this Application.

OPG's ROE proposal is described at Ex. C1-1-1. This account is necessary to reduce the significant risk associated with relying on long-term forecasts of ROE, which protects both customers and OPG symmetrically. This type of account has been approved by the OEB in previous proceedings (e.g. in Hydro One's EB-2013-0416/EB-2014-0247 application).

This account is proposed to take effect on January 1, 2018.

6.4 Hydroelectric Capital Structure Variance Account

OPG proposes establishing the Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that is underpinning the hydroelectric payment amounts in this proceeding for 2017 to 2021.

OPG's Application for hydroelectric to apply the price-cap formula (described in Ex. A1-3-2) to 2014-2015 hydroelectric payment amounts implicitly incorporates the capital structure of 45 per cent equity and 55 per cent debt that was approved by the OEB in EB-2013-0321 that would underpin the proposed hydroelectric payment amounts in the test period. However, in this Application OPG is proposing a capital structure of 49 per cent equity and 51 per cent debt, as described in Ex. C1-1-1. As of the effective date of the payment amounts order in this proceeding, entries into this account would record the annual hydroelectric revenue requirement impact of the difference between the 45 per cent equity/55 per cent debt capital structure approved by the OEB in EB-2013-0321 and the capital structure approved in this proceeding.

To facilitate calculating the annual hydroelectric revenue requirement impact of the difference, OPG proposes to multiply the difference in capital structure each year by the average 2014-2015 regulated hydroelectric rate base forecast approved by the OEB in EB-2013-0321.

OPG's capital structure proposal is described at Ex. C1-1-1. This account is necessary to apply OPG's regulated operations-wide capital structure to the nuclear and regulated hydroelectric businesses consistently during the test period.

This account is proposed to take effect on the effective date of the payment amounts established pursuant to this Application.

7.0 INTEREST

OPG proposes to record interest on all deferral and variance accounts unless specified otherwise in the account descriptions above. For these accounts, OPG proposes to apply interest to the monthly opening balances of these accounts at the interest rate set by the OEB from time to time pursuant to its interest policy for deferral and variance accounts, unless specified otherwise in the account descriptions above.

The 2015 year-end balances were calculated using the current prescribed rate of 1.10 per cent per annum, where applicable.

The reference amounts used to determine entries into the account are as follows:

- From January 1, 2015 until the effective date of the payment amounts order in this proceeding, for both the nuclear and regulated hydroelectric facilities: the average of the monthly income tax provision for 2014 and 2015 underpinning the revenue requirement that was approved by the OEB in EB-2013-0321. As per the EB-2014-0370 payment amounts order, the monthly reference amount is $4.83M (Appendix B, page 7);
- As of the effective date of the payment amounts order in this proceeding, for the regulated hydroelectric facilities: OPG proposes the average of the monthly income tax provision for 2014-2015 underpinning the hydroelectric revenue requirement approved by the OEB in EB-2013-0321;
- As of the effective date of the payment amounts order in this proceeding, for nuclear facilities: OPG proposes on a monthly basis, 1/12 of the annual income tax provision underpinning the corresponding annual nuclear revenue requirements approved by the OEB in this proceeding.

The derivation of the credit addition to the nuclear portion of this account of $4.2M in 2015 is shown in Ex. H1-1-1 Table 6.[13] That addition to the nuclear portion of this account, which was recorded following the resolution during 2015 of the 2011 taxation year audit to reflect the related increase in the Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits ("ITCs") recognition percentage from 75 per cent to 100 per cent for 2011. The addition is the same in nature and calculation as the equivalent SR&ED ITCs impacts previously recorded in the account in relation to resolution of prior year tax audits. SR&ED ITCs are discussed further in Ex. F4-2-1.

5.6 Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account was established pursuant to section 6(2)4 of O. Reg. 53/05 to record variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of,

[13] The credit addition to the regulated hydroelectric portion of the account in 2015 was less than $0.05M.

refurbish or add operating capacity to a prescribed generation facility referred to in section 2 of O. Reg. 53/05 and those forecast costs and firm financial commitments underpinning the revenue requirement that was approved by the OEB. 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"). As required by O. Reg. 53/05, Section 6(2)4, this account will continue to include assessment costs and pre-engineering costs and commitments.[14]

Entries into the account will record variances as follows:

- Until the effective date of the payment amounts order in this proceeding, for both the nuclear and regulated hydroelectric facilities: the variance between actual capital and non-capital costs and firm financial commitments and those capital and non-capital forecast costs and firm financial commitments underpinning the revenue requirement approved by the OEB in EB-2013-0321[15];
- As of the effective date of the payment amounts order in this proceeding, for the regulated hydroelectric facilities: OPG proposes the variance between actual capital and non-capital costs and firm financial commitments and the 2014-2015 average forecast capital and non-capital costs and firm financial commitments underpinning the hydroelectric revenue requirement approved by the OEB in EB-2013-0321;
- As of the effective date of the payment amounts order in this proceeding, for nuclear facilities: OPG proposes the variance between actual capital and non-capital costs and firm financial commitments and those forecast capital and non-capital costs and firm financial commitments underpinning the annual nuclear revenue requirements approved by the OEB in this proceeding.

The derivation of the debit entry into the regulated hydroelectric portion of this account for 2015 of $1.2M is shown in Ex. H1-1-1 Table 7. That relatively small entry was due to

[14] The methodology used to record entries into this account is the same as previously approved by the OEB.
[15] OPG shall ensure that amounts recorded in the account do not include those that OPG indicated it is not seeking to recover from, or refund to, ratepayers as part of the differences between the revenue requirement in its pre-filed evidence dated September 27, 2013 and the information based on OPG's 2014-2016 Business Plan. These amounts are outlined in OPG's Impact Statement dated December 6, 2013, as found at EB-2013-0321, Ex. N1-1-1 Chart 1.

variances in respect of several projects across the regulated hydroelectric fleet. The December 31, 2015 regulated hydroelectric balance in the account is a debit of $83.2M, as shown in Ex. H1-1-1 Table 1. The regulated hydroelectric balance relates largely to the Niagara Tunnel Project.

The derivation of the credit entry into the nuclear portion of this account for 2015 of $68.9M is shown in Ex. H1-1-1 Table 11. That entry was largely due to a ratepayer credit recorded on account of the tax deduction for DRP-related SR&ED expenditures and non-capital credit additions (i.e., OM&A expenses) to the account associated with the DRP, the Fuel Channel Life Cycle Management Project and Pickering Continued Operations, partly offset by the debit non-capital additions for the Fuel Channel Life Extension Project. The DRP and associated capital expenditures and in-service amounts are discussed in Ex. D2-2-1 and accompanying exhibits. The DRP OM&A expenses are discussed in Ex. F2-7-1. Further information on the Pickering Extended Operations initiative and related fuel channel work can be found in Ex. F2-2-3.

5.7 Pension and OPEB Cost Variance Account

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:

(1) the pension and OPEB costs, plus related income tax PILs, reflected in the current revenue requirement approved by the OEB (i.e., the reference amount); and,

(2) OPG's actual pension and OPEB costs, and associated tax impacts, for the 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.

The balance in this account as at December 31, 2012, including interest accrued to that date, was split into the Historic Recovery and Future Recovery components, as ordered by the OEB in EB-2012-0002. In order to facilitate the presentation of entries into the account, OPG

CRVA-eligible projects for this period, the base payment amounts include no associated costs, and the full revenue requirement impact of these in service amounts would be recorded in the account. As discussed in section 4.0 below, the ultimate recovery of these amounts would be subject to a test that ensures no 'double recovery' of these amounts through capital-related revenues during the IR period.

4.0 PREVENTING DOUBLE RECOVERY

In principle, OPG understands that rate-setting through a price-cap index decouples payments and costs. As a result, it is not strictly accurate to state that approved payment amounts fund a specific level of capital expenditures during the IRM period. Under this form of incentive rate-setting, a regulated entity retains the discretion to manage its business within the envelope of funding provided, responding to its individual cost pressures and opportunities to make efficiency gains.

However, while O. Reg. 53/05 requires that OPG recover prudently incurred costs associated with CRVA-eligible projects, it does not permit OPG to recover those costs once in base payment amounts and again through disposition of deferral and variance accounts. In that context, OPG acknowledges that it would only be appropriate for it to recover any balance in the CRVA if it can demonstrate that the costs of the projects recorded in the account have not been funded through base payment amounts during the 2017-2021 period.

Therefore, in OPG's submission, it would only be necessary for the OEB to allow recovery of CRVA balances if OPG's total prudent capital spending in the 2017 to 2021 period (i.e., CRVA-eligible and Sustaining Capital projects combined) exceeds the total amount of such capital spending implicitly funded through base payment amounts.

As a practical matter the depreciation expense in base payment amounts represents the source of cash flow that will be available to fund capital expenditures during the 2017 to 2021 period, escalated by the annual price-cap index adjustments approved by the OEB during the term. OPG has calculated the annual total of these amounts, escalated by the proposed 1.5% price-cap index in Table 3 of this schedule. At the production level reflected in approved "going in" payment amounts, these components of the IRM payment amounts would provide approximately $749M in revenues that could be invested in capital over the IR period.

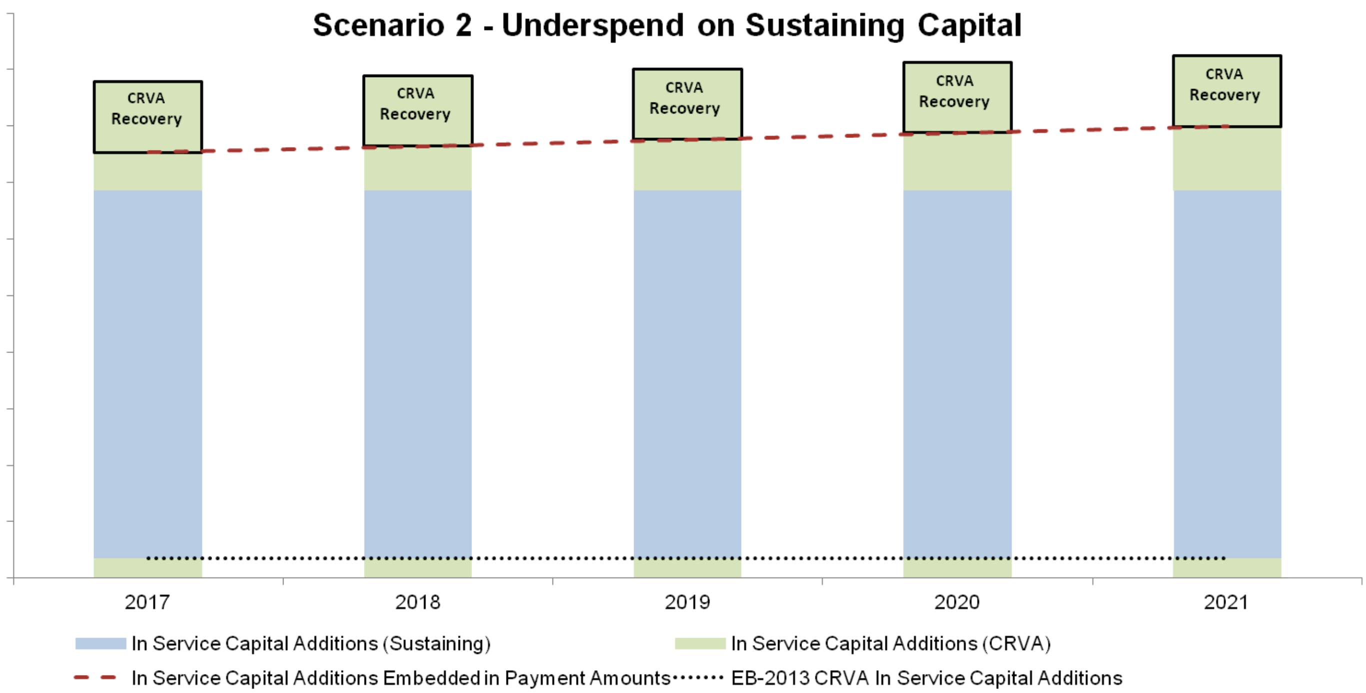

Chart 2

Hydro CRVA Clearance Methodology (Scenario 2: Underspend on Sustaining Capital)

Line No.	Description	2017	2018	2019	2020	2021	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Illustrative Actual CRVA-Related In-Service Additions	25.0	25.0	25.0	25.0	25.0	125.0
2	Revenue Requirement Impact of CRVA Related In-Service Additions[1]	1.3	3.8	6.3	8.8	11.3	31.3
3	CRVA amounts in Payment Amount (Credit to CRVA)[2] *(Per EB-2013-0321)*	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(4.7)
4	Balance in CRVA Account *(line 2 + line 3)*	0.3	2.8	5.3	7.8	10.3	26.5
CRVA Recoverability Threshold							
5	Total In-Service Additions Funded Through Payment Amounts[3]	145.4	147.6	149.8	152.0	154.3	749.1
6	Illustrative Actual Sustaining-Related In-Service Additions	130.0	130.0	130.0	130.0	130.0	650.0
7	Illustrative Actual CRVA-Related In-Service Additions	25.0	25.0	25.0	25.0	25.0	125.0
8	Total Illustrative In-Service Additions	155.0	155.0	155.0	155.0	155.0	775.0
9	In Service Additions Not Funded Through Rates *(line 8 - line 5)*	9.6	7.4	5.2	3.0	0.7	25.9
10	Revenue Requirement Impact of In Service Additions Not Funded Through Payment Amount[1]	0.5	1.3	2.0	2.4	2.6	8.7
11	Maximum Recoverable CRVA Balance (Lesser of Line 4 and Line 10)[4]						8.7

Notes:

1 Approximate Revenue Requirement Impact of 10%, and assuming 1/2 year rule
2 Revenue Requirement Impact of EB-2013-0321 Average of 2014 and 2015 CRVA In Service Additions (See H1-1-2 Table 1 line 16)
3 H1-1-2 Table 3 Line 1
4 Limited to a credit $4.7M - representing the CRVA related in-service additions funded through rates at line 3

Table 3
Total Hydroelectric In-Service Additions Funded Through Payment Amounts

Line No.	Description	EB-2013-0321 Average	2017	2018	2019	2020	2021	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Funding Available for Capital Expenditures[1,2]	143.3	145.4	147.6	149.8	152.0	154.3	749.1

Notes:
1 Average of 2014 and 2015 OEB Approved depreciation calculated as the sum of EB-2013-0321 Payment Amounts Order Table 1 line 17 columns c and f and Table 2 line 17 columns c and f, divided by two
2 Escalated each year at 1.5% per OPG's proposed I-X formula

Capital Funded in Rates

Escalator	1.50%
Rate Base at Start	7,507.7
Capital Envelope Built Into Base Rates	
Depreciation/Amortization	143.3
Cost of Debt	199.4
ROE	315.2
PILs	78.6
Total in Base Rates	736.5
Percentage of Rate Base	9.81%

	2017	***2018***	***2019***	***2020***	***2021***	***Total***
Funding Envelope	747.6	758.8	770.2	781.7	793.4	3,851.7
Rate Base Without Additions						
Opening	7,507.7	7,364.4	7,221.2	7,077.9	6,934.6	
Depreciation	143.3	143.3	143.3	143.3	143.3	716.3
Closing	7,364.4	7,221.2	7,077.9	6,934.6	6,791.4	
Rate Base Funded	7,620.3	7,734.6	7,850.6	7,968.4	8,087.9	
Available Capital Additions	255.9	257.6	259.3	261.0	262.8	1,296.6
Cumulative Additions	255.9	513.5	772.7	1,033.8	1,296.6	

Chart 1

Summary of Revenue Requirement Impact of Nuclear Liabilities ($M)

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	**Pre-Tax Revenue Requirement Impact**	Ex. N1-1-1 Table 2, line 6	167.1	162.6	173.4	158.2	89.1	750.5
2	**Regulatory Income Tax Impact of Nuclear Liabilities Costs and Segregated Fund Contributions**	Ex. N1-1-1 Table 2, line 7	55.7	54.2	57.8	52.7	29.7	250.2
3	**Revenue Requirement Impact of Nuclear Liabilities Costs** *(Ex. N1-1-1 Table 2, line 8)*	line 1 + line 2	222.8	216.8	231.2	211.0	118.8	1,000.6
4	**Regulatory Income Tax Impact of Nuclear Liabilities Expenditures and Segregated Fund Disbursements**	Ex. N1-1-1 Chart 3.2.1, line 17	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)	(214.2)
5	**Total Revenue Requirement Impact - Prescribed Facilities**	line 3 + line 4	178.4	169.4	193.8	167.1	77.7	786.4
	Bruce Facilities							
6	**Pre-Tax Revenue Rrequirement Impact (Impact on Bruce Lease Net Revenues)**	Ex. N1-1-1 Table 2, line 15	156.4	150.4	153.1	157.7	148.6	766.2
7	**Regulatory Income Tax Impact**	Ex. N1-1-1 Table 2, line 16	52.1	50.1	51.0	52.6	49.5	255.4
8	**Total Revenue Requriement Impact - Bruce Facilities** *(Ex. N1-1-1 Table 2, line 17)*	line 6 + line 7	208.6	200.5	204.1	210.3	198.1	1,021.6
	Total Nuclear Liabilities							
9	**Total Pre-Tax Revenue Requirement Impact**	line 1 + line 6	323.5	313.0	326.5	315.9	237.7	1,516.7
10	**Total Regulatory Income Tax Impact**	line 2 + line 4 + line 7	63.5	56.9	71.4	61.4	38.1	291.3
11	**Total Revenue Requirement Impact - Prescribed and Bruce Facilities**	line 9 + line 10	387.0	369.9	397.9	377.4	275.8	1,808.0

As at December 31, 2016, the Decommissioning Segregated Fund ("DF") was overfunded at approximately 121% and the Used Fuel Segregated Fund ("UFF") was marginally overfunded at less than 1%, relative to the corresponding funding obligations per the 2017 ONFA Reference Plan. As reflected in Ex. N1-1-1, OPG expected this to result in overall zero required contributions to each of the funds until the next ONFA reference plan is approved. On January 30, 2017, OPG submitted to the Province a proposed contribution schedule based on the 2017 ONFA Reference Plan that reflected zero overall contributions to each of the funds. This proposed contribution schedule was approved by the Province on February 28, 2017 ("2017 ONFA Contribution Schedule"). The approved 2017-2021 contributions to the UFF are found in Attachment 1 and to the DF in Attachment 2.

Consistent with OPG's 2017-2019 Business Plan, Ex. N1-1-1 reflected a zero contribution to the segregated funds for each of prescribed facilities and Bruce facilities starting in 2017. However, although each of the segregated funds was fully funded in aggregate, the portion of the 2017 ONFA Reference Plan funding obligations related to the prescribed facilities was

Chart 1A

Impact of 2017 ONFA Contribution Schedule Relative to Ex. N1-1-1:

Projected Entries into Deferral and Variance Accounts ($M)

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	Forecast Segregated Fund Contributions per Ex. N1-1-1	Ex. N1-1-1 Table 3, line 14	0.0	0.0	0.0	0.0	0.0	0.0
2	Forecast Segregated Fund Contributions per 2017 ONFA Contribution Schedule		102.5	102.5	102.5	102.5	102.5	512.5
3	Decrease in Regulatory Taxable Income	line 1 - line 2	(102.5)	(102.5)	(102.5)	(102.5)	(102.5)	(512.5)
4	Impact to Be Recorded in Nuclear Liability Deferral Account *(i.e. Regulatory Income Tax Impact of Segregated Fund Contributions)*	line 3 x 25% / (1-25%)	(34.2)	(34.2)	(34.2)	(34.2)	(34.2)	(170.8)
	Bruce Facilities							
5	Forecast Segregated Fund Earnings per Ex. N1-1-1	Ex. N1-1-1 Table 4, line 13	395.8	412.5	429.5	446.1	462.3	2,146.2
6	Forecast Segregated Fund Earnings Reflecting 2017 ONFA Contribution Schedule		393.1	404.4	415.9	426.9	437.6	2,077.9
7	Decrease in Segregated Fund Earnings	line 5 - line 6	2.6	8.1	13.6	19.2	24.7	68.2
8	Impact on Bruce Facilities' Income Taxes	line 7 x 25%	(0.7)	(2.0)	(3.4)	(4.8)	(6.2)	(17.1)
9	Impact to Be Recorded in Bruce Lease Net Revenues Variance Account	line 7 + line 8	2.0	6.0	10.2	14.4	18.6	51.2
10	Total Projected Deferral and Variance Account Entries *(Net Credit to Ratepayers)*	line 4 + line 9	(32.2)	(28.1)	(24.0)	(19.8)	(15.6)	(119.7)

In addition, there are differences between the projected impacts of the 2017 ONFA Reference Plan reflected in Ex. N1-1-1 and the actual impacts reflecting the difference between the projected and actual year-end 2016 ARO adjustment, and the difference between the projected and actual year-end 2016 discount rate used to determine variable expenses.[4] OPG estimates that, over the 2017-2021 period, these differences will result in incremental credit entries totaling approximately $95M in the Nuclear Liability Deferral Account and approximately $80M in the Bruce Lease Net Revenues Variance Account, relative to Ex. N1-1-1 forecasts. The actual year-end 2016 ARO adjustment was reflected in OPG's 2016 audited consolidated financial statements published on March 10, 2017.

Prior to 2017, OPG made overall contributions to the UFF every quarter since the fund's inception. OPG has not made contributions to the DF, as it has been fully funded or overfunded each time a new contribution schedule was established based on an approved

[4] See Ex. N1-1-1, p. 17, footnote 14 for further details. Variable expenses are also discussed in section 3.1 of this exhibit.

OPG is proposing to update the 2017 to 2021 nuclear revenue requirement in the following five areas, as discussed in greater detail in section 3.0:

- changes to forecast pension and OPEB cash amounts, including the impact of the latest filed pension funding valuation as of January 1, 2016 and an assumed subsequent valuation as of January 1, 2019 (see section 3.1);
- changes to forecast costs associated with OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities"), including the projected impact of the 2017 ONFA Reference Plan effective January 1, 2017[4], as well as the income tax impacts of changes to forecast cash expenditures on nuclear waste management and decommissioning and corresponding disbursements from the nuclear segregated funds (see section 3.2);
- changes to Bruce Lease net revenues and related tax effects as a result of an updated forecast of used fuel and L&ILW revenues, under the amended Bruce Lease, for changes in revenue rates reflecting the 2017 ONFA Reference Plan cost estimates and new waste volume forecasts provided by Bruce Power LP (see section 3.3);
- an update to the forecast ROE amounts and related tax effects to reflect the most recent OEB-published Cost of Capital parameters (see section 3.4); and
- an increase in forecast Nuclear base OM&A costs resulting from new Fitness for Duty requirements from the CNSC (see section 3.5).

There are two consequential changes to the nuclear revenue requirements, also presented in Chart 2.0, as a result of the five changes identified above:

- an increase in nuclear stretch factor dollars as a result of the changes in Nuclear OM&A included in this Impact Statement; and
- the elimination of IR period regulatory tax loss carry forwards, as a result of the changes in regulatory taxable income arising from the items included in this Impact Statement (see section 3.6).

[4] Any difference between the projected impacts and the final impacts for the prescribed facilities arising from the approved 2017 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account. Any such differences related to the Bruce facilities will be recorded in the Bruce Lease Net Revenues Variance Account.

deferred under rate smoothing. The updated approvals are detailed below. Prior to the oral hearing, OPG will file with the OEB an amendment to Ex. A1-2-2 Approvals to reflect these changes and to Ex. A1-3-4 Drivers of Deficiency to reflect the changes in the drivers of revenue deficiency for the nuclear facilities over the IR period. As noted above, OPG is not updating its request for smoothed nuclear payment amounts or riders, and therefore there is no change to the annualized residential consumer impact of OPG's Application.

Nuclear Revenue Requirement

1. The approval of the following revised revenue requirements for the nuclear facilities, net of the nuclear stretch factor, for each year of the IR period:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,201.8M
January 1, 2018 through December 31, 2018	$3,222.5M
January 1, 2019 through December 31, 2019	$3,309.6M
January 1, 2020 through December 31, 2020	$3,824.4M
January 1, 2021 through December 31, 2021	$3,437.8M

Nuclear Rate Base

2. The approval of the following revised rate base values for the nuclear facilities for each year of the IR period:[16]

Year	Rate Base
2017	$3,868.4M
2018	$3,960.6M
2019	$3,819.3M
2020	$7,786.2M
2021	$8,208.6M

[16] The changes to rate base values from the pre-filed evidence represent changes in forecast ARC balances, as a result of the projected year-end 2016 ARO/ARC adjustment to reflect changes in the nuclear liabilities related to the 2017 ONFA Reference Plan.

ATTACHMENT 1

Approved Used Fuel Fund Quarterly Contributions 2017-2021($)						
	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Bruce A	Bruce B	Darlington	Total
3/31/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/29/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/29/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/30/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/29/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/28/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/29/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/28/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/31/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/31/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0

ATTACHMENT 2

Approved Decommissioning Fund Quarterly Contributions 2017-2021($)						
	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Bruce A	Bruce B	Darlington	Total
3/31/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/29/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/29/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/30/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/29/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/28/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/29/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/28/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0

Chart 3.2.1

Summary of Revenue Requirement Changes – Nuclear Liabilities ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
	Nuclear Liabilities Costs						
	Original Submission:						
1	Prescribed Facilities	Ex. C2-1-1 Table 1, line 8	144.9	137.7	120.6	180.4	137.5
2	Bruce Facilities	Ex. C2-1-1 Table 1, line 17	309.4	312.4	318.5	325.6	306.5
3	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 1 + line 2	454.3	450.1	439.1	506.0	444.0
	N1 Update:						
5	Prescribed Facilities	Ex. N1-1-1 Table 2, line 8	222.8	216.8	231.3	211.0	118.8
6	Bruce Facilities	Ex. N1-1-1 Table 2, line 17	208.6	200.5	204.1	210.3	198.1
7	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 5 + line 6	431.4	417.3	435.4	421.2	316.9
8	Revenue Requirement Impact of Update	line 7 - line 3	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)
	Expenditures on Nuclear Waste Management and Decommissioning and Segregated Fund Disbursements						
	Original Submission:						
9	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 13	166.0	177.4	200.6	230.7	228.0
10	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 4	85.0	108.3	140.0	208.4	191.6
11	Regulatory Taxable Income impact	line 10 - line 9	(80.9)	(69.0)	(60.6)	(22.3)	(36.5)
12	Income Tax Impact	line 11 x 25% / (1-25%)	(27.0)	(23.0)	(20.2)	(7.4)	(12.2)
	N1 Update:						
13	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 8	217.5	227.9	232.8	283.6	317.0
14	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 15	84.4	85.7	120.4	152.0	193.7
15	Regulatory Taxable Income impact	line 13 + line 14	(133.1)	(142.2)	(112.4)	(131.6)	(123.3)
16	Income Tax Impact	line 15 x 25% / (1-25%)	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)
17	Revenue Requirement Impact of Update	line 16 - line 12	(17.4)	(24.4)	(17.3)	(36.4)	(29.0)
18	Total Revenue Requirement Impact of Updates Related to Nuclear Liabilities	line 8 + line 17	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)

Table 2
Updated Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
(Updated Ex. C2-1-1 Table 1)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note or Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	PRESCRIBED FACILITIES						
1	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 3	77.3	77.3	77.3	77.3	7.9
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 3	51.4	53.1	65.7	52.5	52.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 3	12.5	10.1	12.2	14.0	15.9
	Return on ARC in Rate Base:						
4	**Return on Rate Base at Weighted Average Accretion Rate**	Note 1	25.9	22.1	18.3	14.5	12.4
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		167.1	162.6	173.4	158.2	89.1
7	**Income Tax Impact**	Note 2	55.7	54.2	57.8	52.7	29.7
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		222.8	216.8	231.2	211.0	118.8
	BRUCE FACILITIES						
9	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 4	68.6	68.6	68.6	68.6	68.6
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 4	71.0	68.1	73.0	78.6	63.5
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 4	2.7	3.2	3.0	3.6	5.0
12	**Accretion Expense**	Ex. N1-1-1 Table 4	462.1	473.2	489.1	505.6	523.4
13	**Less: Segregated Fund Earnings (Losses)**	Ex. N1-1-1 Table 4	395.8	412.5	429.5	446.1	462.3
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		156.4	150.4	153.1	157.7	148.6
16	**Income Tax Impact** (line 15 x tax rate / (1-tax rate))	Note 4	52.1	50.1	51.0	52.6	49.5
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		208.6	200.5	204.1	210.3	198.1
18	**Total Revenue Requirement Impact - Prescribed and Bruce Facilities**		431.4	417.3	435.4	421.2	316.9
	(line 8 + line 17)						

See Ex. N1-1-1 Table 2a for notes

Table 2a
Updated Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2017 to 2021
(Updated Ex. C2-1-1 Table 1a)
Notes to Ex. N1-1-1, Table 2

Notes:
1 The lesser of average Unfunded Nuclear Liabilities (UNL) and average Asset Retirement Costs (ARC) for the prescribed facilities earns the weighted average accretion rate. The amount, if any, by which average ARC exceeds average UNL earns the weighted average cost of capital (WACC).

Table to Note 1

Line No.	Year	*(from Ex. N1-1-1 Table 3, line 26)* Average ARC ($M)	*(from Ex. N1-1-1 Table 3, line 20)* Average UNL ($M)	*(a) - (b)* ARC-UNL ($M)	Weighted Average Accretion Rate#	WACC Rate+	*col. (d) x Ex. N1-1-1 Table 3, line 27* Return on Rate Base at Accretion Rate ($M)	*(c) x (e) if >0* Return on Rate Base at WACC ($M)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	2017	524.0	770.1	(246.1)	4.95%	6.80%	25.9	0.0
2a	2018	446.7	757.8	(311.1)	4.95%	6.66%	22.1	0.0
3a	2019	369.5	755.7	(386.3)	4.95%	6.63%	18.3	0.0
4a	2020	292.2	759.2	(467.0)	4.95%	6.61%	14.5	0.0
5a	2021	249.6	752.1	(502.5)	4.95%	6.60%	12.4	0.0

\# From Ex. N1-1-1, section 3.3.2
\+ Reflects the 2017 ROE value published by the OEB on October 27, 2016 (see Ex. N1-1-1, section 3.4)

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1b	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. N1-1-1, Table 2, line 6)	167.1	162.6	173.4	158.2	89.1
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. N1-1-1 Table 3, line 14)	0.0	0.0	0.0	0.0	0.0
3b	Net Increase in Regulatory Taxable Income (line 1b - line 2b)	167.1	162.6	173.4	158.2	89.1
4b	Income Tax Rate (Note 4)	25.00%	25.00%	25.00%	25.00%	25.00%
5b	Income Tax Impact (line 3b x line 4b / (1 - line 4b))	55.7	54.2	57.8	52.7	29.7

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 3 ($M)

Line No.	Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1c	Increase in Temporary Differences (Ex. N1-1-1 Table 2, lines 9 through 13)	208.6	200.5	204.1	210.3	198.1
2c	Income Tax Rate (Note 4)	25.00%	25.00%	25.00%	25.00%	25.00%
3c	Impact on Bruce Facilities' Income Taxes (line 1c x line 2c)	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)

4 Income tax rates are from Ex. F4-2-1 Table 3a, line 29.

Table 3
Prescribed Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 2)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		9,246.3				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		9,010.6	9,347.5	9,677.7	10,033.6	10,342.6
5	**Used Fuel Storage and Disposal Variable Expenses**	3	51.4	53.1	65.7	52.5	52.9
6	**Low & Intermediate Level Waste Management Variable Expenses**	4	12.5	10.1	12.2	14.0	15.9
7	**Accretion Expense**		490.5	495.0	510.8	526.1	541.6
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(217.5)	(227.9)	(232.8)	(283.6)	(317.0)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		9,347.5	9,677.7	10,033.6	10,342.6	10,636.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		9,179.0	9,512.6	9,855.7	10,188.1	10,489.3
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		8,240.1	8,577.8	8,931.7	9,268.2	9,589.6
13	**Earnings (Losses)**		422.2	439.6	456.9	473.4	488.9
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(84.4)	(85.7)	(120.4)	(152.0)	(193.7)
16	**Closing Balance** (lines 12 through 15)		8,577.8	8,931.7	9,268.2	9,589.6	9,884.9
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		8,409.0	8,754.8	9,099.9	9,428.9	9,737.2
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)						
18	**Opening Balance** (line 4 - line 12)		770.5	769.6	746.0	765.4	752.9
19	**Closing Balance** (line 10 - line 16)		769.6	746.0	765.4	752.9	751.2
20	**Average Unfunded Nuclear Liability Balance** ((line 18 + line 19)/2)		770.1	757.8	755.7	759.2	752.1
	ASSET RETIREMENT COSTS (ARC)						
21	**2016 Projected Closing Balance Before Year-End Adjustments**		800.5				
22	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
23	**Opening Balance** (col. (a): line 21 + line 22)		562.6	485.4	408.1	330.8	253.5
24	**Depreciation Expense**		(77.3)	(77.3)	(77.3)	(77.3)	(7.9)
25	**Closing Balance Before Year-End Adjustments** (line 23 + line 24)		485.4	408.1	330.8	253.5	245.6
26	**Average Asset Retirement Costs** ((line 23 + line 25)/2)		524.0	446.7	369.5	292.2	249.6
27	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 20 or line 26)		524.0	446.7	369.5	292.2	249.6

Notes:
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the 2017 Approved ONFA Reference Plan.
2 Adjustment expected to be recorded on December 31, 2016 associated with the change to the previous cost estimates related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences. Although these facilities were not included in the 2012 ONFA Reference Plan (see Ex. C2-1-1 Table 2, Note 6), they are included in the 2017 ONFA Reference Plan. As a result, the ARO is projected to increase by $4.4M at December 31, 2016, of which $2.2M is attributed to the prescribed facilities and $2.2M to the Bruce facilities. In accordance with GAAP, this amount will be expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility that is not used to support OPG's current operations.
3 See Ex. C2-1-1 Table 2, Note 3.
4 See Ex. C2-1-1 Table 2, Note 4.

Table 4
Bruce Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 3)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		11,373.1				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		10,083.5	10,462.3	10,842.5	11,209.0	11,595.8
5	**Used Fuel Storage and Disposal Variable Expenses**		71.0	68.1	73.0	78.6	63.5
6	**Low & Intermediate Level Waste Management Variable Expenses**		2.7	3.2	3.0	3.6	5.0
7	**Accretion Expense**		462.1	473.2	489.1	505.6	523.4
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(157.0)	(164.2)	(198.6)	(201.0)	(215.7)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		10,462.3	10,842.5	11,209.0	11,595.8	11,972.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		10,272.9	10,652.4	11,025.8	11,402.4	11,783.9
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		7,720.1	8,045.3	8,386.9	8,722.7	9,049.2
13	**Earnings (Losses)**		395.8	412.5	429.5	446.1	462.3
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(70.5)	(70.9)	(93.7)	(119.7)	(144.3)
16	**Closing Balance** (line 12 through 15)		8,045.3	8,386.9	8,722.7	9,049.2	9,367.1
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		7,882.7	8,216.1	8,554.8	8,885.9	9,208.1
	ASSET RETIREMENT COSTS (ARC)						
18	**2016 Projected Closing Balance Before Year-End Adjustments**		4,290.7				
19	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
20	**Opening Balance** (col. (a): line 18 + line 19)		2,999.0	2,930.4	2,861.9	2,793.3	2,724.8
21	**Depreciation Expense**		(68.6)	(68.6)	(68.6)	(68.6)	(68.6)
22	**Closing Balance** (line 20 + line 21)		2,930.4	2,861.9	2,793.3	2,724.8	2,656.2
23	**Average Asset Retirement Costs** ((line 20 + line 22)/2))		2,964.7	2,896.1	2,827.6	2,759.0	2,690.5

Notes
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the Approved 2017 ONFA Reference Plan
2 See Ex. N1-1-1 Table 3, Note 2.

determined in accordance with the ONFA, currently at 5.15% per annum. This results in the same projected funded status of the funds, in percentage terms, as the actual status at the time the projection is made. In dollar terms, the projected surplus amount in each of the funds increases at the rate of growth of the funding liability.[22] Under this approach, based on the actual December 31, 2016 balances, the UFF is projected to continue to be marginally overfunded at less than 1% over the 2017-2021 period, while the DFF is projected to continue to be approximately 121% funded. The resulting surplus amounts for each of the funds over the period are as follows:

Chart 2

Segregated Fund Surplus Amounts ($M)

	2016 Actual	2017 Projection	2018 Projection	2019 Projection	2020 Projection	2021 Projection
Used Fuel Fund[23]	25	27	28	29	31	33
Decommissioning Fund	1,477	1,553	1,633	1,717	1,806	1,899

The actual funded status of the funds over the next 5 years cannot be predicted with any certainty because it will depend on the actual market performance of the assets and thus can differ significantly from the above forecast.

As noted in Ex. L-8.1-2 AMPCO-147, the OEB addressed the matter of the Due to Province amounts related to the segregated funds in EB-2013-0321. The pre-filed evidence and Ex. N1-1-1 in this Application reflect these findings. Specifically, the OEB found the following in the EB-2013-0321 Decision with Reasons:

The Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are "Due to Province" as stipulated in the Ontario Nuclear

[22] This principle also is explained in Ex. L-8.1-15 SEC-091.
[23] Calculated net of amounts Due to Province related to the committed return on the guaranteed portion of the UFF. In contrast, Due to Province amounts for the UFF presented in Ex. L-8.1-2 AMPCO-147 (corrected version) wholly represented those related to the committed return adjustment. The UFF was underfunded at the time the projection reflected in that interrogatory response was developed, based on the actual year-end 2015 funded status.

the amounts that you're referencing from G2-2-1, the original pre-filed evidence.

MR. WALKER: That's a significant improvement, is it not, sir?

MR. MAUTI: Yes, it is. And there would be subsequent changes as well as a result of the filing of the C2-1-1, C2-1-2 evidence, the update on nuclear liabilities, primarily driven from the approved contribution schedule from ONFA, as well as finalization with the year-end audited statements of the ARO adjustment and finalizing some of the impacts that were only known at the end of the year on things like discount rates, which go into the amounts that are charged to Bruce Power for waste that's produced going forward.

MR. KOGAN: And those impacts as we have proposed would be subject to deferral and variance account treatment, for clarity, relative to the N1-1-1 impacts that are actually in our proposed updated revenue requirement.

MS. LONG: So what is the new revised number? Mr. Walker is quoting the 401, you have the N1-1 impact, and then the nuclear liabilities impact. Can you tell the Panel what the new 401 is?

MR. MAUTI: If you added all the changes up it's approximately a 90 million net cost to ratepayers as opposed to the original 401, and I believe in N1-1-1, if I added those numbers, they would be more than 90 million. So it's down to about a 90 million over the five years.

MS. LONG: Thank you.

from the N1. So just by reference, Exhibit N1, tab 1, schedule 1, table 4 does update this for N1.

But what we don't have on record is a corresponding number -- the most recent number, which is the updated C2 file which corresponds to the 90 million. That was not on record, because those things were proposing to flow through the D&V account. So to make matters more complex, that’s the flow of it.

MR. WALKER: I'm not sure whether to ask for an undertaking to have this number updated or not.

MR. MAUTI: We can give you the number from the N111. The equivalent average asset retirement cost would be 2 billion 690.5.

MR. WALKER: Thank you. A clarification point; can I take you back to page 16 of our compendium? Do you see here where the net book value of Bruce is $3.8 billion as of the end of the test period?

MR. KOGAN: Yes.

MR. WALKER: Has that is that changed materially as a consequence of your N1 filing?

MR. KOGAN: Yes, it would change similarly in the magnitude to the other delta that you just discussed with Mr. Mauti.

MR. WALKER: Could I ask you what that number is?

MR. KOGAN: I don't have that exact number. But to help you understand how these numbers flow, using your compendium, the 3794.9 at page 16 subsumes the number at your page 15, line 23, column I, which is the closing