SEC Interrogatory #2

Interrogatory

Reference: [H1-1, p.49-51]

Question:

With respect to the Sale of Unprescribed Kipling Site Deferral Account:

a. Please confirm the Kipling Site was owned by Ontario Power Generation Inc. and not by any affiliate.
b. Please allocate both the net proceeds and gain on sale between, a) land, and b) buildings and other depreciable property. Please detail the basis of the allocation.
c. Please provide a breakdown of the net gain on sale calculation.
d. Please provide a continuity schedule for the Kipling Site from 2008 to its disposition.
e. Please confirm that the portion of the asset service fee for the Kipling Site Deferral Account includes depreciation, and cost of capital (grossed up for taxes).
f. Please confirm that the asset service calculation related to the Kipling Site, mathematically, results in largely the same outcome as would be derived from a revenue requirement calculation.
g. For each year since 2008, please provide the total asset service fees for the Kipling Site that were a) included in rates, and b) allocated to the regulated business. Please further breakdown the information into nuclear and hydroelectric.
h. [p.51] OPG says, “Additionally, ratepayers have not been previously charged for costs related to the asset retirement and environmental liabilities carried on OPG’s balance sheet in connection with the Kipling Site.” Please explain what those costs are, and if they had been charged to ratepayers, what they would have been and the basis for it.
i. If the OEB disagrees with OPG’s position and determines that ratepayers should receive the benefit of the proceeds and/or gains of disposition of the Kipling Site, please provide OPG’s view of how that should be done.

Response

a. Confirmed.

b. Neither the net proceeds from, nor the gain on the sale of the premises at 800 Kipling Avenue in Toronto (“Kipling Site”) were allocated between land and buildings and other depreciable property for fixed asset accounting purposes in OPG’s financial records, as it was not necessary to do so. Net proceeds received were recorded in, and assets and liabilities related to the Kipling Site were removed from the general ledger, the net impact of which resulted in the overall gain on the sale. Proceeds from the sale were allocated between land and tax depreciable property for corporate income tax return purposes. On that basis, approximately $17 million of the proceeds was allocated to depreciable property, with the remainder allocated to the land.

c. Please refer to Chart 1 below for a breakdown of the total net gain on the sale of the Kipling Site, recognized over 2022 and 2023.

Chart 1 – Calculation of Net Gain on Sale of Kipling Site[1]

Description	($M)
Proceeds from sale	197.2
Less: Commission and transaction costs	(1.1)
Net proceeds from sale	**196.1**
Less: Adjustments	
Removal of Kipling Site net book value	34.6
Reversal of asset retirement obligation	(6.8)
Reversal of environmental liability	(5.1)
Other	0.6
Total Adjustments	23.3
Pre-tax gain on sale	172.8
Less: Tax expense	41.2
After-tax gain on sale[2]	**131.6**

[1] Numbers may not add due to rounding.
[2] The calculation contains further refinements of approximately $2 million to the income tax expense relative to the after-tax gain on sale amounts cited at Ex. H1-1-1, p. 50, lines 9 and 14-15.

d. Please refer to Attachment 1, Tables 1 and 2.

e. Not confirmed. The balance in the Sale of Unprescribed Kipling Site Deferral Account does not contain any asset service fees. The balance represents 23% of the net proceeds from the sale of the Kipling Site.

For clarity, asset services fees charged to OPG's regulated and unregulated generation businesses in connection with the Kipling Site prior to its sale were calculated based on components reflecting depreciation expense and cost of capital (grossed-up for taxes) in connection with the asset. As shown in Attachment 2, Table 1, a total of approximately $3.4M for the depreciation component and approximately $6.4M for the cost of capital component (grossed-up for taxes) was recovered through OPG's payment amounts since 2008.

f. Confirmed.

g. Please refer to Attachment 2, Tables 1-3.

h. As the owner of the Kipling Site, OPG carried an asset retirement obligation and environmental liabilities on its balance sheet related to decommissioning and removal of facilities at the end of their useful life as well as future site remediation in compliance with environmental laws. The basis for charging a portion of these accrued costs to ratepayers would have been the same as the basis for charging the components of the existing asset service fee, being the partial use of the Kipling Site by the regulated operations (i.e., these costs could have formed an additional component of the asset service fees). As discussed in Ex. H1-1-1, section 5.25 and shown in part c) above, the reversal of these liabilities upon the sale of the property contributed approximately $12M toward the total pre-tax gain on sale.

i. In responding to this question, OPG notes that the OEB-approved Settlement Proposal in EB-2020-0290 limits the amount that the parties may take a position should be credited to ratepayers in respect of the Kipling Site sale to the amount tracked in the Unprescribed Sale of Kipling Site Deferral Account. If the OEB disagrees with OPG's position and determines that a portion of the amount tracked in the account should be credited to ratepayers as part of this Application, OPG believes that this could be reasonably accomplished by amortizing the resulting amount over a 30-month period of July 1, 2024 to December 31, 2026, as part of the proposed payment riders for the other deferral and variance accounts. For administrative simplicity, the credit amortization could be split evenly between the regulated hydroelectric and nuclear payment riders.

Table 1
Kipling Site - Continuity of Gross Property, Plant and Equipment ($M)
Years Ending December 31, 2008 to 2021[1]

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b) + (c) Net Change	(a) + (d) Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	2008	24.2	6.2	-	6.2	30.4
2	2009	30.4	0.3	-	0.3	30.7
3	2010	30.7	1.0	-	1.0	31.7
4	2011	31.7	1.5	-	1.5	33.2
5	2012	33.2	2.7	-	2.7	36.0
6	2013	36.0	0.1	-	0.1	36.1
7	2014	36.1	2.3	-	2.3	38.4
8	2015	38.4	0.4	-	0.4	38.8
9	2016	38.8	1.8	-	1.8	40.6
10	2017	40.6	2.3	-	2.3	42.9
11	2018	42.9	1.9	(0.1)	1.9	44.8
12	2019	44.8	2.9	(0.4)	2.5	47.3
13	2020	47.3	1.9	-	1.9	49.2
14	2021	49.2	1.8	-	1.8	51.0

Table 2
Kipling Site - Continuity of Accumulated Depreciation ($M)
Years Ending December 31, 2008 to 2021[1]

Line No.	Year	Opening Balance	Depreciation	Retirements, Transfers & Adjustments	(b) + (c) Net Change	(a) + (d) Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	2008	3.4	0.6	-	0.6	4.0
2	2009	4.0	0.7	-	0.7	4.7
3	2010	4.7	0.7	-	0.7	5.4
4	2011	5.4	0.8	-	0.8	6.1
5	2012	6.1	0.8	-	0.8	7.0
6	2013	7.0	0.9	-	0.9	7.8
7	2014	7.8	0.9	-	0.9	8.7
8	2015	8.7	1.0	-	1.0	9.7
9	2016	9.7	1.0	-	1.0	10.7
10	2017	10.7	1.1	-	1.1	11.7
11	2018	11.7	1.2	(0.1)	1.1	12.9
12	2019	12.9	1.2	(0.1)	1.2	14.0
13	2020	14.0	1.3	-	1.3	15.3
14	2021	15.3	1.1	-	1.1	16.4
Kipling Site - Net Property, Plant, Equipment - Year Ending December 31, 2021[1] (Table 1, line 14, col. (e) - Table 2, line 14, col. (e))						34.6

Notes:
1 As of December 31, 2021 the site was classified as an asset held for sale in accordance with generally accepted accounting principles and was no longer depreciated.

Table 1
Kipling Site Asset Service Fees - Nuclear and Regulated Hydroelectric ($M)[1]

Line No.	Component	2008 OEB Approved	2009 OEB Approved	2010 Note 2	2011 OEB Approved	2012 OEB Approved
		(a)	(b)	(c)	(d)	(e)
1	Depreciation Expense	0.1	0.1	0.1	0.1	0.1
2	Property Tax	0.3	0.3	0.3	0.3	0.3
3	Tax-adjusted Return	0.4	0.5	0.5	0.5	0.5
4	Operating Costs	2.8	2.9	2.9	3.3	3.3
5	**Total**	**3.6**	**3.8**	**3.7**	**4.2**	**4.2**

Line No.	Component	2013 Note 2	2014 OEB Approved	2015 OEB Approved	2016 Note 2	2017 OEB Approved[3]
		(a)	(b)	(c)	(d)	(e)
6	Depreciation Expense	0.1	0.2	0.3	0.3	0.3
7	Property Tax	0.3	0.3	0.3	0.3	0.3
8	Tax-adjusted Return	0.5	0.4	0.4	0.4	0.5
9	Operating Costs	3.3	3.0	3.1	3.0	1.7
10	**Total**	**4.2**	**4.0**	**4.0**	**4.0**	**2.8**

Line No.	Component	2018 OEB Approved[3]	2019 OEB Approved[3]	2020 OEB Approved[3]	2021 OEB Approved[3]	2022 OEB Approved[3]
		(a)	(b)	(c)	(d)	(e)
11	Depreciation Expense	0.3	0.4	0.4	0.5	0.0
12	Property Tax	0.3	0.3	0.3	0.3	0.0
13	Tax-adjusted Return	0.5	0.5	0.5	0.5	0.0
14	Operating Costs	1.6	1.7	1.7	1.7	0.4
15	**Total**	**2.8**	**2.8**	**2.9**	**2.9**	**0.5**

Line No.	Component	Total 2008-2022[4]
		(a)
16	Depreciation Expense	3.4
17	Property Tax	4.3
18	Tax-adjusted Return	6.4
19	Operating Costs	36.4
20	**Total**	**50.5**

Notes:
1. Amounts for 2008-2021 as filed in EB-2020-0290, Ex. JT3.12, Attachment 1, Table 1.
2. Annual OEB-approved amounts are shown for the applicable years covered by EB-2007-0905, EB-2010-0008, EB-2013-0321, EB-2016-0152 and EB-2020-0290. For 2010, 2013 and 2016, there were no separate OEB-approved amounts; figures shown for these years reflect the average of OEB-approved amounts for the corresponding preceding two years reflecting the continuation of existing payment amounts.
3. For regulated hydroelectric, OEB-approved amounts for 2017-2022 represent the average of the 2014 and 2015 annual amounts per EB-2013-0321. Nuclear payment amounts approved beginning January 1, 2022 contain no asset service fee recovery for the Kipling Site.
4. Sum of cols. (a) to (e), lines 1-4, 6-9, 11-14.

Numbers may not add due to rounding.

Table 2
Kipling Site Asset Service Fees - Nuclear ($M)

Line No.	Component	2008 OEB Approved	2009 OEB Approved	2010 Note 1	2011 OEB Approved	2012 OEB Approved
		(a)	(b)	(c)	(d)	(e)
1	Depreciation Expense	0.1	0.1	0.1	0.1	0.1
2	Property Tax	0.3	0.3	0.3	0.3	0.3
3	Tax-adjusted Return	0.4	0.5	0.5	0.4	0.4
4	Operating Costs	2.5	2.6	2.6	3.0	3.0
5	**Total**	**3.3**	**3.5**	**3.4**	**3.8**	**3.8**

Line No.	Component	2013 Note 1	2014 OEB Approved	2015 OEB Approved	2016 Note 1	2017 OEB Approved
		(a)	(b)	(c)	(d)	(e)
6	Depreciation Expense	0.1	0.2	0.3	0.2	0.3
7	Property Tax	0.3	0.3	0.3	0.3	0.3
8	Tax-adjusted Return	0.4	0.4	0.4	0.4	0.5
9	Operating Costs	3.0	2.5	2.6	2.6	1.2
10	**Total**	**3.8**	**3.4**	**3.5**	**3.4**	**2.3**

Line No.	Component	2018 OEB Approved	2019 OEB Approved	2020 OEB Approved	2021 OEB Approved	2022 OEB Approved[2]
		(a)	(b)	(c)	(d)	(e)
11	Depreciation Expense	0.3	0.4	0.4	0.4	-
12	Property Tax	0.3	0.3	0.3	0.3	-
13	Tax-adjusted Return	0.4	0.4	0.4	0.4	-
14	Operating Costs	1.2	1.2	1.3	1.3	-
15	**Total**	**2.2**	**2.3**	**2.4**	**2.4**	**-**

Line No.	Component	Total 2008-2022[3]
		(a)
16	Depreciation Expense	3.1
17	Property Tax	3.9
18	Tax-adjusted Return	5.9
19	Operating Costs	30.5
20	**Total**	**43.5**

Notes:
1. Annual OEB-approved amounts are shown for the applicable years covered by EB-2007-0905, EB-2010-0008, EB-2013-0321, EB-2016-0152 and EB-2020-0290. For 2010, 2013 and 2016, there were no separate OEB-approved; amounts; figures shown for these years reflect the average of OEB-approved amounts for the corresponding preceding two years.
2. Nuclear payment amounts approved beginning January 1, 2022 contain no asset service fee recovery for the Kipling Site.
3. Sum of cols. (a) to (e), lines 1-4, 6-9, 11-14.

Table 3
Kipling Site Asset Service Fees - Regulated Hydroelectric ($M)

Line No.	Component	2008 OEB Approved	2009 OEB Approved	2010 Note 1	2011 OEB Approved	2012 OEB Approved
		(a)	(b)	(c)	(d)	(e)
1	Depreciation Expense	-	-	-	0.0	0.0
2	Property Tax	-	-	-	0.0	0.0
3	Tax-adjusted Return	-	-	-	0.0	0.0
4	Operating Costs	0.3	0.3	0.3	0.3	0.3
5	**Total**	**0.3**	**0.3**	**0.3**	**0.4**	**0.4**

Line No.	Component	2013 Note 1	2014 OEB Approved	2015 OEB Approved	2016 Note 1	2017 OEB Approved[2]
		(a)	(b)	(c)	(d)	(e)
6	Depreciation Expense	0.0	0.0	0.0	0.0	0.0
7	Property Tax	0.0	0.0	0.0	0.0	0.0
8	Tax-adjusted Return	0.0	0.0	0.0	0.0	0.0
9	Operating Costs	0.3	0.5	0.5	0.5	0.4
10	**Total**	**0.4**	**0.6**	**0.6**	**0.6**	**0.5**

Line No.	Component	2018 OEB Approved[2]	2019 OEB Approved[2]	2020 OEB Approved[2]	2021 OEB Approved[2]	2022 OEB Approved[2]
		(a)	(b)	(c)	(d)	(e)
11	Depreciation Expense	0.0	0.0	0.0	0.0	0.0
12	Property Tax	0.0	0.0	0.0	0.0	0.0
13	Tax-adjusted Return	0.0	0.0	0.0	0.0	0.0
14	Operating Costs	0.4	0.4	0.4	0.4	0.4
15	**Total**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

Line No.	Component	Total 2008-2022[3]
		(a)
16	Depreciation Expense	0.3
17	Property Tax	0.3
18	Tax-adjusted Return	0.5
19	Operating Costs	5.9
20	**Total**	**7.0**

Notes:

1 Annual OEB-approved amounts are shown for the applicable years covered by EB-2007-0905, EB-2010-0008, EB-2013-0321 and EB-2016-0152. For 2010, 2013 and 2016, there were no separate OEB-approved amounts; figures shown for these years reflect the average of OEB-approved amounts for the corresponding preceding two years.

2 For regulated hydroelectric, OEB-approved amounts for 2017-2022 represent the average of the 2014 and 2015 annual amounts per EB-2013-0321.

3 Sum of cols. (a) to (e), lines 1-4, 6-9, 11-14.

SEC Interrogatory #3

Interrogatory

Reference: [H1-1-1, Attachment 3, p.1]

Question:

OPG calculation of economic loss includes when "the forecasted market revenues from PGS generation in the next on-peak period would be insufficient to recover the costs of pumping in the current off-peak period." Please explain how OPG defines "next on-peak period" and how it forecasts the market price for that period.

Response

With regards to cycling the SAB Pump Generating Station, OPG refers to "next on-peak" as the immediately following 7:00 to 23:00 hour period.

The forecast of market price for the next on-peak period is informed by IESO published pre-dispatch prices and modified as necessary using OPG proprietary weather and demand forecasts as well as real-time assessments of the generation stack, transmission constraints, and neighbouring market conditions.

SEC Interrogatory #4

Interrogatory

Reference: [H1-1-1, Attachment 3, p.3-73]

Question:

OPG has provided a table that shows each hour when OPG did not pump the PGS and where an entry into the SBGVA was made:

a. For each hour in the table, please provide the following additional information:

   i. Total MWh
   ii. Approved Payment Amount
   iii. HOEP
   iv. Forecast HOEP in next on-peak period
   v. GRC costs
   vi. Total forecast revenues in current off-peak period (before GRC costs)
   vii. Total forecast revenues in the next on-peak period (before GRC costs)
   viii. Costs associated with Pumping – Load Charges
   ix. Costs associated with Pumping – Opportunity cost of SAB 1 and 2 forgone productions while the PGS is pumping
   x. Cost associated with Pumping - Other
   xi. Total entry into SBGVA

Please provide the response in Excel format.

b. Part (a) seeks to better understand and verify the conditions in each hour that OPG says would have led to an economic loss if the OPG pumped water into the PGS. If there is further data and information that would explain the decision that is not being requested in part (a), please include it.

c. If there was no sharing of HIM revenue with customers, what impact would it have on the number of hours where OPG determined there was an economic loss, if it was to pump the PGS?

Response

a. Refer to Attachment 1 (Confidential) where OPG has provided the requested data.

OPG notes the following:

- Column iv: instead of the HOEP in next on-peak period, OPG has provided the average pre-dispatch market clearing price in the next period as published each hour from the IESO PD-3 schedule. This is the best available representation of HOEP used by operators in real-time. Refer to Ex. L-H-SEC-03 for additional information on forecasted market prices.

- Column vi: Not available, as OPG does not forecast revenues in off-peak periods.

- Columns vii through x: Calculated based on one PGS unit either pumping or generating at efficiency for one hour.

- Column xii: OPG has included the estimated loss if one PGS unit pumped for one hour at efficiency as calculated by the PGS utilization assessment methodology.

- Column vii: The "NSR" label is applied to all hours when Hydro One's Network Service Charge is applicable. OPG seeks to avoid operating the PGS in pump mode in consideration to the magnitude of the charge[1] and in alignment with the practice of PGS operating in generation mode in on-peak hours.

- In the preparation of this response, OPG identified 107 hours between 2018 and 2021 that were incorrectly categorized as "uneconomic" and should not have been included in Ex. H1-1-1, Attachment 3. Those hours have been excluded from Attachment 1 of this interrogatory response, and OPG will file a correction to Ex. H1-1-1, Attachment 3. OPG will also file a correction to the 2021 Hydroelectric Surplus Baseload Generation RRR by June 30, 2024.

b. In addition to the material provided in response to part (a), the following factors also affect the economics of pumping at the PGS:

  - While the losses in column xii in Attachment 1 are calculated using the IESO's pre-dispatch HOEP forecast, this does not directly reflect the forecasted market prices in the next on-peak period used for decision making. In practice, operators also consider OPG's proprietary price forecast which is based on OPG's view on weather, demand, and other

[1] Hydro One's current rates can be found in the OEB's EB-2022-0250 Decision and Order. For example, one PGS unit pumping for 1 hour could incur a charge of $207,200. In response to that prohibitively large cost, OPG seeks to avoid pumping during the hours when the network service charge is applied.

market conditions. These forecasts are not archived and as such unavailable to be provided.

- The efficiency factors for the Sir Adam Beck 1 and Sir Adam Beck 2 stations (SAB) and the PGS in pump and generation mode are required in the analysis of the economics of PGS cycling. OPG cannot provide these specific values due to their commercial sensitivity as they relate to offer information that could impact OPG as a market participant or competition in the IESO administered market.

- OPG assesses the downstream impact of water pumped and discharged by the PGS on SAB based on i) whether pumped water could instead be used to generate at SAB, and ii) whether discharged water could be incrementally generated at SAB based on available capacity. These factors have a significant impact on the overall efficiency of PGS cycling as they determine if shifting generation at PGS is further realized as shifted generation at SAB. This information is provided in Attachment 1 as columns xiii and xiv on a confidential basis, as the combination of details provided in Attachment 1 can be used to derive commercially sensitive information as they relate to offer information that could impact OPG as a market participant or competition in the IESO administered market.

c. HIM revenue sharing is not considered in the economic decision making for PGS operations and therefore would have no impact on the number of hours where OPG determined using the PGS will result in an economic loss.

SEC Interrogatory #5

Interrogatory

Reference: [H1-1-1, Attachment 3, p.3-73]

Question:

Please provide a similar table that shows all hours when an entry into the SBGVA was made, that includes, a) the year, hour, and day, b) the total amount of the entry, c) the number of MWh, d) HOEP, and e) the reason for the entry. Please provide the response in Excel format.

Response

OPG has provided Attachment 1 containing all requested data with the exception of "the reason for the entry." Since EB-2010-0008, all entries to the SBGVA are made pursuant to the corresponding decisions and orders of the OEB.

OPG notes that its SBG spill algorithm computes the full impact of SBG conditions on OPG generation by (i) quantifying SBG spill in hours when HOEP is less than the applicable GRC, and (ii) identifying instances of spill in non-SBG hours within that day not attributable to other reasons[1] and allocates this spill as SBG spill if in a previous SBG hour within that day[2], the algorithm identifies energy that would have been generated absent SBG conditions but was not realized as actual spill. For this reason, Attachment 1 shows SBGVA entries in hours when HOEP exceeds OPG's applicable GRC rather than the originating SBG hour.

[1] For list of other reasons, please see EB-2013-0321, Ex. E1-2-1,p. 3.
[2] For Sir Adam Beck GS, the look-back period includes two or four hours of the previous day, based on tourist hours.

Staff Interrogatory #1

Interrogatory

Ref: (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 11-12
(2) Exhibit H1 / Tab 1 / Schedule 1 / Table 6

Preamble:

OPG recorded four entries to the Income and other Taxes Variance account in 2020, 2021 and 2022. Two of the four entries are as follows:

- Credit entries in 2020, 2021 and 2022 related to a CCA rule change pursuant to the passing of Bill C-97, the Budget Implementation Act, 2019, No. 1 in 2019, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018, referred to as accelerated investment incentive property ("AIIP").
- A credit entry related to an increase in the recognition of SR&ED ITCs for the 2016 taxation year from 75% to 100%, based on the resolution of the 2016 income tax audit in 2021.

Question(s):

a) Please explain why the SR&ED ITCs recognition percentages have increased from 75% to 100% for the 2016 taxation year, following their respective audits.

   i. Please provide the relevant page(s) of the 2016 income tax audit report to substantiate the percentage change.

b) Please provide the supporting 2020, 2021 and 2022 CCA difference calculations for:

   i. Nuclear (2020: $10.1M) line 3 Table 6
   ii. Nuclear (2021: $8.0M) & Hydroelectric (2021: $8.1M) line 4 Table 6
   iii. Hydroelectric (2022: $10.8M) line 5 Table 6

Response

a) Consistent with past proceedings including EB-2020-0290,[1] the amount of ITCs recognized for accounting purposes is determined based on an assessment of the

[1] EB-2020-0290, Ex. F4-2-1, p.11, lines 19 to 29

likelihood of their allowance, in accordance with generally accepted accounting principles. Specifically, OPG recognizes 75% of the estimated ITCs for taxation years that are subject to audit. This is also the basis upon which forecast SR&ED ITCs are included in the revenue requirement, including those underpinning the EB-2013-0321 payment amounts that were in effect during 2016. Once the tax audit is completed without adjustments to the SR&ED ITCs claimed, as was the case for the 2016 taxation year, the likelihood of allowance becomes 100% and OPG recognizes the previously unrecognized 25% of the SR&ED ITC amount, recording a corresponding credit entry into the Income and Other Taxes Variance Account (for the nuclear facilities for periods prior to June 1, 2017 and for the regulated hydroelectric facilities) or the SR&ED ITC Variance Account (for the nuclear facilities for periods beginning June 1, 2017).

Please refer to Attachment 1 (confidential) for the Summary of Adjustments issued by the Ontario Ministry of Finance for the 2016 taxation year.

b) Please refer to the following for the requested supporting calculations in connection with Ex. H1-1-1, Table 6, lines 3-5:

i. Attachment 2: Nuclear (2020: $10.1M)
ii. Attachment 3: Nuclear (2021: $8.0M)
iii. Attachment 4: Hydroelectric (2021: $8.1M)
iv. Attachment 5: Hydroelectric (2022: $10.8M)

The calculations were performed using the same methodologies as in EB-2020-0290.

In Tables 2 and 3 of these attachments, the cost of acquisitions in Column (b) includes the cost of acquisition of accelerated investment incentive property (“AIIP”), which is also separately shown in Column (c). The 50% of the amount of the non-AIIP property cost is calculated as 50% of the difference between Column (b) and Column (c) and is included in the 50% Rule Column (g). Column (g) is then reduced by 50% of the AIIP cost in Column (c). CCA is then calculated based on the difference between Column (f) and Column (g), where Column (f) includes 100% of Column (b). This results in CCA being calculated using the old rules on non-AIIP property additions (i.e., at 50%) and based on the enhanced rules for AIIP property (i.e., three times the allowed amount under the old rules).

EX. L-H-STAFF-01 ATTACHMENT 1 IS CONFIDENTIAL IN ITS ENTIRETY

SUMMARY OF ADJUSTMENTS FOR THE 2016 TAXATION YEAR

Table 1
Calculation of Income and Other Taxes Variance Account for Regulated Nuclear Operations
Accelerated Investment Incentive CCA Impact ($M)
December 31, 2020

Line No.		Note	2020
			(a)
1	**Nuclear CCA in EB-2016-0152 with Accelerated CCA**	1	211.5
2	**Nuclear CCA in EB-2016-0152**	2	201.4
3	**Increase in CCA** (Line 1- Line 2)	3	10.1

Notes:
1 Ex. L-H-Staff-01, Attachment 2, Table 2, line 22, col. (k).
2 EB-2016-0152 Payment Amounts Order, Table 19, line 12, col. (c) ($582.2M) less EB-2016-0152 DRP CCA from EB-2016-0152 Ex. F4-2-1, Table 3b, Note 3 for 2020 ($380.8M).
3 Ex. H1-1-1, Table 6, line 3, col. (b).

Table 2
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations with Accelerated CCA ($M)
Year Ending December 31, 2020

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**1**	981.0	56.1	44.6	0.0	0.0	1,037.0	(16.6)	1,053.6	4%	0.0	42.1	994.9
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	239.6	7.2	5.8	0.0	0.0	246.9	(2.1)	249.0	6%	0.0	14.9	231.9
4	**1.1-rolling start**	0.7	0.0	0.0	0.0	0.0	0.7	0.0	0.7	6%	0.0	0.0	0.7
5	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	299.5	51.3	43.4	0.0	0.0	350.8	(17.8)	368.6	20%	0.0	73.7	277.1
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	23.0	8.8	7.4	0.0	0.0	31.9	(2.9)	34.8	30%	0.0	10.4	21.4
11	**12**	3.8	19.5	17.2	0.0	0.0	23.3	1.1	22.2	100%	0.0	22.2	1.1
12	**13**	0.9	0.0	0.0	0.0	0.0	0.9	0.0	0.9	N/A	0.0	0.1	0.8
13	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
15	**17**	432.2	43.2	32.0	0.0	0.0	475.4	(10.4)	485.8	8%	0.0	38.9	436.5
16	**17-rolling start**	65.1	0.3	0.3	0.0	0.0	65.4	(0.1)	65.5	8%	0.0	5.2	60.1
17	**42**	1.4	0.3	0.3	0.0	0.0	1.7	(0.1)	1.8	12%	0.0	0.2	1.5
18	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
19	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
20	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
21	**50**	2.3	2.8	2.8	0.0	0.0	5.1	(1.4)	6.5	55%	0.0	3.6	1.5
22	**Total**	2,049.6	189.6	153.7	0.0	0.0	2,239.2	(50.3)	2,289.5		0.0	211.5	2,027.7

Notes:
1 As filed in EB-2020-0290, Ex. L-H1-01-Staff-326, Attachment 4, Table 2, col. (l).

Table 1
Calculation of Income and Other Taxes Variance Account for Regulated Nuclear Operations
Accelerated Investment Incentive CCA Impact ($M)
December 31, 2021

Line No.		Note	2021
			(a)
1	**Nuclear CCA in EB-2016-0152 with Accelerated CCA**	1	199.2
2	**Nuclear CCA in EB-2016-0152**	2	191.2
3	**Increase in CCA** (Line 1- Line 2)	3	8.0

Notes:

1 Ex. L-H-Staff-01, Attachment 3, Table 2, line 22, col. (k).

2 EB-2016-0152 Payment Amounts Order, Table 20, line 12, col. (c) ($574.4M) less EB-2016-0152 DRP CCA EB-2016-0152 Ex. F4-2-1, Table 3b, Note 3 for 2021 ($383.2M).

3 Ex. H1-1-1, Table 6, line 4, col. (e).

Numbers may not add due to rounding.

Table 2
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations with Accelerated CCA ($M)
Year Ending December 31, 2021

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**1**	994.9	44.5	40.0	0.0	0.0	1,039.4	(17.7)	1,057.1	4%	0.0	42.3	997.1
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	231.9	6.0	5.7	0.0	0.0	238.0	(2.6)	240.6	6%	0.0	14.4	223.5
4	**1.1-rolling start**	0.7	0.0	0.0	0.0	0.0	0.7	0.0	0.7	6%	0.0	0.0	0.6
5	**2**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	277.1	44.9	42.9	0.0	0.0	322.0	(20.4)	342.4	20%	0.0	68.5	253.5
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	21.4	7.7	7.3	0.0	0.0	29.1	(3.4)	32.6	30%	0.0	9.8	19.3
11	**12**	1.1	17.7	17.1	0.0	0.0	18.9	0.3	18.6	100%	0.0	18.6	0.3
12	**13**	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.8	N/A	0.0	0.1	0.7
13	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
15	**17**	436.5	22.4	19.5	0.0	0.0	458.9	(8.3)	467.2	8%	0.0	37.4	421.5
16	**17-rolling start**	60.1	0.0	0.0	0.0	0.0	60.1	0.0	60.1	8%	0.0	4.8	55.3
17	**42**	1.5	0.3	0.3	0.0	0.0	1.8	(0.1)	1.9	12%	0.0	0.2	1.6
18	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
19	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
20	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
21	**50**	1.5	2.8	2.8	0.0	0.0	4.3	(1.4)	5.7	55%	0.0	3.2	1.2
22	**Total**	2,027.7	146.3	135.4	0.0	0.0	2,174.0	(53.7)	2,227.8		0.0	199.2	1,974.8

Table 1
Calculation of Income and Other Taxes Variance Account for Regulated Hydroelectric Operations
Accelerated Investment Incentive CCA Impact ($M)
December 31, 2021

Line No.		Note	2014	2015	Average
			(a)	(b)	(c)
1	**Hydroelectric CCA in EB-2013-0321 with Accelerated CCA**	1	238.8	229.3	234.0
2	**Hydroelectric CCA in EB-2013-0321**	2	227.1	218.6	222.9
3	**Additional CCA** (Line 1- Line 2)				11.2
4	**Percentage Eligible**	3			73%
5	**2021 CCA Differences** (Line 3 x Line 4)	4			8.1

Notes:
1. Ex. L-H-Staff-01, Attachment 4, Tables 2 and 3, line 22, col. (k).
2. EB-2020-0290, Ex. L-H1-01-Staff-326, Attachment 2, Table 1, line 2.
3. Percentage eligible was calculated as the ratio of the 2021 non-Capacity Refurbishment Variance Account AIIP in-service additions to total 2021 non-Capacity Refurbishment Variance Account in-service additions. Consistent with EB-2020-0290 and as noted at Ex. H1-1-1, Table 6, note 1, the impact of AIIP rules on Capacity Refurbishment Variance Account eligible projects is recorded in the Capacity Refurbishment Variance Account.
4. Ex. H1-1-1, Table 6, line 4, col. (d).

Numbers may not add due to rounding.

Table 2
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Hydroelectric Operations with Accelerated CCA ($M)
Year Ending December 31, 2014[1]

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**1**	1,705.4	29.2	31.2	(4.4)	0.0	1,730.1	(15.7)	1,745.8	4%	0.0	69.8	1,660.3
2	**1-rolling start**	320.1	0.0	0.0	0.0	0.0	320.1	0.0	320.1	4%	0.0	12.8	307.3
3	**1.1**	19.2	0.6	0.6	(0.0)	0.0	19.8	(0.3)	20.1	6%	0.0	1.2	18.6
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	1,670.7	0.0	0.0	0.0	0.0	1,670.7	0.0	1,670.7	6%	0.0	100.2	1,570.4
6	**3**	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.8
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	43.7	19.1	19.1	(1.5)	0.0	61.3	(8.8)	70.2	20%	0.0	14.0	47.3
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	5.0	4.1	4.1	(0.3)	0.0	8.7	(1.9)	10.6	30%	0.0	3.2	5.5
11	**12**	5.1	6.0	6.0	(0.5)	0.0	10.6	0.0	10.6	100%	0.0	10.6	0.0
12	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0
13	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
15	**17**	247.3	23.3	23.3	(1.8)	0.0	268.8	(10.7)	279.5	8%	0.0	22.4	246.4
16	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**42**	3.9	0.2	0.2	(0.0)	0.0	4.1	(0.1)	4.2	12%	0.0	0.5	3.6
18	**43.1**	0.4	0.0	0.0	0.0	0.0	0.4	0.0	0.4	30%	0.0	0.1	0.3
19	**43.2**	6.1	0.0	0.0	0.0	0.0	6.1	0.0	6.1	50%	0.0	3.1	3.1
20	**45**	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.2	45%	0.0	0.1	0.1
21	**50**	0.9	0.3	0.3	(0.0)	0.0	1.2	(0.2)	1.4	55%	0.0	0.8	0.5
22	**Total**	4,028.8	82.8	84.8	(8.6)	0.0	4,103.0	(37.6)	4,140.6		0.0	238.8	3,864.1

Notes:
1 As filed in EB-2020-0290, Ex. L-H1-01-Staff-326, Attachment 2, Table 2.

Numbers may not add due to rounding.

Table 3
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations with Accelerated CCA ($M)
Year Ending December 31, 2015[1]

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[2]	Cost of Acquisitions	Cost of Acquisitions that are AIIP	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(d)-(e) UCC1	50% Rule	(f)-(g) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(f)+(j)-(k) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**1**	1,660.3	37.1	37.1	(3.3)	0.0	1,694.1	(16.9)	1,711.0	4%	0.0	68.4	1,625.7
2	**1-rolling start**	307.3	0.0	0.0	0.0	0.0	307.3	0.0	307.3	4%	0.0	12.3	295.0
3	**1.1**	18.6	2.2	2.2	(0.2)	0.0	20.6	(1.0)	21.5	6%	0.0	1.3	19.3
4	**1.1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6%	0.0	0.0	0.0
5	**2**	1,570.4	0.0	0.0	0.0	0.0	1,570.4	0.0	1,570.4	6%	0.0	94.2	1,476.2
6	**3**	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.8	5%	0.0	0.0	0.7
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	47.3	24.9	24.9	(3.6)	0.0	68.577	(10.6)	79.2	20%	0.0	15.8	52.7
9	**8-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20%	0.0	0.0	0.0
10	**10**	5.5	5.3	5.3	(0.8)	0.0	10.1	(2.3)	12.3	30%	0.0	3.7	6.4
11	**12**	0.0	8.8	8.8	(1.2)	0.0	7.7	0.0	7.7	100%	0.0	7.7	0.0
12	**13**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0
13	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7%	0.0	0.0	0.0
14	**14.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5%	0.0	0.0	0.0
15	**17**	246.4	28.2	28.2	(4.0)	0.0	270.6	(12.1)	282.6	8%	0.0	22.6	247.9
16	**17-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8%	0.0	0.0	0.0
17	**42**	3.6	0.2	0.2	(0.0)	0.0	3.8	(0.1)	3.9	12%	0.0	0.5	3.3
18	**43.1**	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.3	30%	0.0	0.1	0.2
19	**43.2**	3.1	0.0	0.0	0.0	0.0	3.1	0.0	3.1	50%	0.0	1.5	1.5
20	**45**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.0	0.0
21	**50**	0.5	1.1	1.1	(0.1)	0.0	1.4	(0.5)	1.9	55%	0.0	1.1	0.4
22	**Total**	3,864.1	107.7	107.7	(13.2)	0.0	3,958.6	(43.4)	4,002.1		0.0	229.3	3,729.4

Notes:
1 As filed in EB-2020-0290, Ex. L-H1-01-Staff-326, Attachment 2, Table 3. Note that the referenced evidence in EB-2020-0290 incorrectly identified the above table as the Undepreciated Capital Cost and Capital Allowance Schedule for OPG's Regulated Nuclear Operations with Accelerated CCA for the year ending December 31, 2019, rather than December 31, 2015.
2 Ex. L-H-Staff-01, Attachment 4, Table 2, col. (l).

Table 1
Calculation of Income and Other Taxes Variance Account for Regulated Hydroelectric Operations
Accelerated Investment Incentive CCA Impact ($M)
December 31, 2022

Line No.		Note	2014	2015	Average
			(a)	(b)	(c)
1	**Hydroelectric CCA in EB-2013-0321 with Accelerated CCA**	1	238.8	229.3	234.0
2	**Hydroelectric CCA in EB-2013-0321**	2	227.1	218.6	222.9
3	**Additional CCA** (Line 1- Line 2)				11.2
4	**Percentage Eligible**	3			97%
5	**2022 CCA Differences** (Line 3 x Line 4)	4			10.8

Notes:

1 Ex. L-H-Staff-01, Attachment 4, Tables 2 and 3, line 22, col. (k).

2 EB-2020-0290, Ex. L-H1-01-Staff-326, Attachment 2, Table 1, line 2.

3 Percentage eligible was calculated as the ratio of the 2022 non-Capacity Refurbishment Variance Account AIIP in-service additions to total 2022 non-Capacity Refurbishment Variance Account in-service additions. Consistent with EB-2020-0290 and as noted at Ex. H1-1-1, Table 6, note 1, the impact of AIIP rules on Capacity Refurbishment Variance Account eligible projects is recorded in the Capacity Refurbishment Variance Account.

4 Ex. H1-1-1, Table 6, line 5, col. (g).

Staff Interrogatory #2

Interrogatory

Reference:
(1) Exhibit H1 / Tab 1 / Schedule 1 / pages 45-46
(2) Exhibit H1 / Tab 1 / Schedule 1 / Table 14

Preamble:

OPG stated that:

- Actual SR&ED ITCs net of tax attributed to the nuclear facilities recorded in 2020 and 2021, inclusive of immediately preceding year's true-up adjustments based on income tax return completion, were lower than the forecast amounts reflected in the corresponding revenue requirements approved in EB-2016-0152.

- Actual SR&ED ITCs net of tax recorded in 2022, inclusive of immediately preceding year's true-up adjustment based on income tax return completion, were higher than the forecast amount reflected in the corresponding revenue requirement approved in EB-2020-0290.

Question(s):

a) Please explain if OPG had undergone any audits for 2020, 2021 and 2022 SR&ED ITCs. If so, please provide any findings from those audits and if these findings have been incorporated into the DVAs.

Response

a) OPG has not yet undergone any tax audits of Scientific Research & Experimental Development ("SR&ED") investment tax credits ("ITCs") for 2020, 2021 or 2022 taxation years. To the extent any such audits for these years result in changes to the SR&ED ITCs, the corresponding impact will be reflected in the SR&ED ITC Variance Account for the nuclear facilities and the Income & Other Taxes Variance Account for the regulated hydroelectric facilities.

Staff Interrogatory #3

Interrogatory

Reference:
Ref: (1) Exhibit H1 / Tab 1 / Schedule 1 / p. 51
(2) Ontario Power Generation Inc. | OSC

Preamble:

OPG stated that:

> The Impact for IFRS Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record financial impacts of transition to and implementation of International Financial Reporting Standard ("IFRS") from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of the Securities Act (Ontario). No entries were recorded in this account in 2022 as OPG has continued to apply US GAAP to report its consolidated financial statements.

OEB staff notes that the exemption granted by OSC for OPG adopting IFRS is subject to certain conditions, potentially resulting in the expiration of the exemption before January 1, 2027.

Question(s):

a) Please provide comments on OPG's plan to transition from US GAAP to IFRS, considering the expiration of the exemptive relief granted by OSC before January 1, 2027.

   i. If so, please provide a schedule and timeline for the transition.
   ii. If not, please explain OPG's plan of requesting an extension of the exemptive relief.

Response

a) OPG declines to provide the requested information on the basis of relevance. This question seeks information that is not relevant to any issue before the OEB in this Application. The Application addresses clearance of amounts from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. The requested commentary on any potential plans to transition from or remain on US GAAP is not within the Application's scope.

Staff Interrogatory #4

Interrogatory

Reference:

(1) Exhibit H1 / Tab 1 / Schedule 1 / p. 29
(2) Exhibit H1 / Tab 1 / Schedule 1 / Attachment 5 / p. 5 / Actuarial Report
(3) Government of Ontario Will Not Appeal Bill 124 Decision | Ontario Newsroom

Preamble:

OPG noted that "OPEB payments attributed to the nuclear facilities for 2020 and 2021 were lower than the reference amounts, primarily due to changes in claim patterns resulting from the COVID-19 pandemic. OPEB payments attributed to the regulated hydroelectric facilities for 2020 to 2022 were higher than the reference amounts, primarily due to a growing retiree population."

On Page 5 of Attachment 5, OPG noted that the actuarial report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2020 to December 31, 2022, as determined in accordance with US GAAP, are as follows:

(in Canadian $ 000's)	January 1, 2020 to December 31, 2020	January 1, 2021 to December 31, 2021	January 1, 2022 to December 31, 2022
RPP	$ 158,857	$ 199,089	$ 85,612
SPP	26,408	26,902	24,859
OPRB	156,539	150,020	154,882
LTD	42,515	35,765	17,403
Total	**$ 384,319**	**$ 411,776**	**$ 282,756**

Question(s):

a) Please confirm whether the impact of the COVID-19 pandemic and the growing retiree population have been fully accounted for in OPG's pension and OPEB costs as noted in the above table. If not, please explain.

b) Please quantify the impact on pension and OPEB accrual costs if the impact(s) from Bill 124 were taken into account.

Response

a) Unlike benefit payments that solely reflect known events at a point in time, pension and OPEB accrual costs are determined using actuarial assumptions that represent estimates or forecasts of economic variables and demographic trends, such as future health care claims costs or future mortality rates. OPG's pension and OPEB accrual costs for 2020 to 2022 reflect actuarial assumptions as of the end of 2019 to 2021, respectively, when the accounting valuations were performed.[1] OPG confirms that these assumptions reflected COVID-19 pandemic impacts and retiree population information that was known and could have been reasonably extrapolated at the time.

   Given the forward-looking nature of the actuarial assumptions, it is not possible for OPG to confirm that all future impacts of the COVID-19 pandemic and the future retiree population patterns have been precisely predicted. Any differences between actual results (or future actuarial assumptions) and actuarial assumptions made in determining pension and other post-retirement benefit costs will give rise to actuarial gains and losses in the normal course, which, in accordance with US GAAP, are accumulated and subject to amortization into costs over future periods.

b) OPG confirms that the impact of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124") was taken into account in determining OPG's actual pension and OPEB costs for 2020, 2021 and 2022, through a salary schedule escalation rate assumption of 1% per year for the duration of the corresponding three-year "moderation period" that was applicable under the legislation. OPG is unable to provide the requested impact of Bill 124 on these costs as this would require OPG to speculate on the salary schedule escalation rate assumption that would have been used to determine each year's costs in an alternate scenario where Bill 124 did not exist at the time.

[1] Long-term disability costs for 2020 to 2022 were calculated using information as of the end of 2020 to 2022, respectively.

Staff Interrogatory #5

Interrogatory

Reference: (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 37-40

Preamble:

OPG noted that over the 2020-2022 period, it recorded debit additions of $105.2M to the Nuclear Development Variance Account in relation to non-capital preliminary planning and preparation costs for a “Darlington SMR”.

On page 39, OPG included a table (Chart 4) with a breakdown of costs over 2020 to 2022. The costs are broken down by four main categories; i) Developer Technology Design and Planning, ii) OPG Project Management and Engineering Oversight, iii) Licencing and iv) OPG Site Specific and Other Activities.

Question(s):

a) Please provide a detailed breakdown of costs identified in Chart 4. As part of the breakdown, please classify whether the line-item costs are external contractor related or internal OPG costs, and whether the costs are capital or non-capital related.

b) Please provide all Business Cases conducted by OPG for projects related to the Nuclear Development Variance Account.

c) If applicable, provide an explanation for any cost overruns in the individual projects outlined in a) and b). For the purpose of this analysis, OPG may assume cost overruns to be cases where actual costs were more than 5 percent the estimated costs (e.g., Business Case costs).

Response

a) See Chart 1 below.

Chart 1 – Breakdown of Ex. H1-1-1 Chart 4 Costs

Description	Cost Category	($M)			
		2020	2021	2022	Grand Total
Developer Technology Design and Planning	External Contractor	2.5	54.5	2.1	59.1
Developer Technology Design and Planning Total		**2.5**	**54.4**	**2.1**	**59.1**
OPG Project Management and Engineering Oversight	External Contractor	2.0	8.5	0.2	10.7
	Internal OPG	2.9	12.7	0.1	15.7
OPG Project Management and Engineering Oversight Total		**4.9**	**21.2**	**0.4**	**26.5**
Licensing	External Contractor	3.2	4.5	-	7.7
	Internal OPG	2.5	3.9	-	6.4
Licensing Total		**5.7**	**8.5**	**-**	**14.2**
OPG Site Specific and Other Activities	External Contractor	-	11.3	(0.3)	11.0
	Internal OPG	-	0.0	0.2	0.2
OPG Site Specific and Other Activities Total		**-**	**11.3**	**(0.1)**	**11.2**
Grand Total		**13.1**	**95.4**	**2.4**	**110.9**

Note: numbers may not add due to rounding

b) There were no business cases prepared for the work underpinning the 2020-2022 costs recorded in the Nuclear Development Variance Account. The amounts recorded were tied to non-capital preliminary planning and preparation costs for an SMR at the Darlington New Nuclear site. As discussed in EB-2020-0290, Ex. F2-8-1, these costs were necessary prior to making an investment decision for the project. See Ex. L-H-CCC-08, Attachment 2 for the OPG Board of Directors' approval associated with these costs.

c) See Ex. L-H-CCC-08, part b).

Staff Interrogatory #6

Interrogatory

Reference: (1) Exhibit H1 / Tab 1 / Schedule 1 / pages 49-50

Preamble:

OPG noted that the sale of the “Kipling Site” resulted in net proceeds of $196.1M and that 23% of the net proceeds are tracked in the “Kipling Site Deferral Account”.

OPG further stated:

> OPG does not propose to clear this tracking account, as OPG’s position is that the net proceeds and net gain on the sale of this unregulated property should accrue entirely to OPG. The Kipling Site was not a prescribed facility under O. Reg. 53/05 and, accordingly, has never been included in OPG’s rate base. Prior to the sale, the Kipling Site primarily supported OPG’s unregulated business and was reported as an unregulated asset in OPG’s financial statements. To the extent that OPG has historically used a portion of the Kipling Site to support the company’s regulated operations, the revenue requirements have included asset service fees, as an ongoing OM&A expense akin to lease payments, charging the regulated operations for such use

Question(s):

a) What is the total amount tracked in the Kipling Site Deferral Account as of December 31, 2023?

b) What is the total amount that ratepayers have contributed in payments towards the “Kipling Site”? Please also provide an annual breakdown of the payments.

c) Please provide any governance documents and presentations to the Board of Directors related to the “Kipling Site”. Please also provide documents that outline the arrangement between the regulated and unregulated uses of the property.

d) What was the leasing arrangement between OPG’s unregulated business and “Kipling Site”? Please outline how this arrangement was similar or different to the arrangement with OPG’s regulated business.

Response

a) The total amount tracked in the Sale of Unprescribed Kipling Site Deferral Account as of December 31, 2023 is $45.1 million, representing 23% of the net proceeds arising from the sale of OPG's site located at 800 Kipling Avenue in Toronto ("Kipling Site").

b) Ratepayers did not contribute any payments toward the Kipling Site. The Kipling Site was a corporate-level asset that was not a prescribed facility and accordingly was not included in rate base. It was used primarily by OPG's unregulated operations and, to a lesser extent, by the regulated operations. Both the regulated generation operations and the unregulated generation operations were charged an asset service fee for their corresponding use of the site. These asset service fees were included as operating costs of each of the businesses and reported as such in OPG's consolidated financial statements and the financial statements for the prescribed facilities. The asset service fees for the Kipling Site recovered through OPG's payment amounts are detailed in Ex. L-H-SEC-02, Attachment 2.

c) and d)

With respect to the request for "any governance documents and presentations to the Board of Directors related to the 'Kipling Site'", OPG declines to answer on the basis that this is not an appropriate question. The question ignores the principle of proportionality, which underlies the interrogatory process, in that it is overly broad and all encompassing. Contrary to the OEB Rules of Practice and Procedure (Section 26.02 (d)), the question does not "contain specific requests for clarification of a party's evidence, documents or other information in the possession of the party and relevant to the proceeding." The question seeks without limit any governance documents and presentations to the Board of Directors related to the "Kipling Site". This would require searching Board of Directors' materials for any reference to the Kipling Site over an unspecified duration of time.

With respect to documents that outline the arrangement between the regulated and unregulated uses of the property, OPG can confirm that there were no formal leasing arrangements for the use of the Kipling Site by either regulated operations or unregulated operations during the time that OPG owned the asset, and thus no associated documents exist. As discussed in part b), both the regulated generation operations and the unregulated generation operations were charged an internal, cost-based asset service fee for their use of the site. The methodology for determining the asset service fees, most recently described in EB-2020-0290, Ex. F3-2-1, pp. 2-3, was previously reviewed and found to be reasonable by external experts in conjunction with OPG's cost allocation methodology, including in EB-2020-0290 (Ex. F3-1-4, Attachment 1, pp. 25-26) and EB-2013-0321 (Ex. F5-5-1,

p. 25). The same methodology was applied to determine the asset service fee charged to the regulated operations and the unregulated operations. As part of the OEB-approved Settlement Proposal in EB-2020-0290, the parties agreed that 23% of the use of the site was attributable to the regulated operations.[1]

[1] EB-2020-0290, Decision and Order, November 15, 2021, Schedule A, Ex. O, p. 30.

Staff Interrogatory #7

Interrogatory

Reference: (1) Exhibit H1 / Tab 1 / Schedule 1 / Attachment 4 / pages 3-4

Preamble:

OPG noted that the "Sir Adam Beck I Generating Station – Unit G5 Major Overhaul" project was placed in service in 2021 with a total cost of $44.7M.

OPG further stated:

> This represented an increase of $9.9M from the Class 2 estimate of $34.8M in the First Execution Business Case. While characterized as a Class 2 estimate at the time, the level of project definition was reflective of a Class 3 estimate, which would have been typical for the phase of the project at that time.
>
> The cost variance was mainly due to greater execution complexity compared to the station's Unit G10 Major Overhaul (discussed above), which was used as a basis for the cost estimate, resulting in greater than expected OEM cost to perform the work. Additionally, actual cost was impacted by the COVID-19 pandemic, including from suspension of on-site work at the pandemic's onset and additional safety protocols upon resumption, and extended dry commissioning phase and equipment failure during wet commissioning.

Question(s):

a) Please elaborate on why the project costs were characterized as a "Class 2 estimate" when the level of project definition was reflective of a "Class 3 estimate".

b) What was the in-service date for the project?

c) Please provide a breakdown of the $44.7M in project costs. As part of the breakdown, please also classify whether the line-item costs are external contractor related or internal OPG costs.

d) Please provide a similar breakdown of costs (as outlined in b)) for the "Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade" project.

e) Please elaborate on why the "Unit G5 Major Overhaul" project was more complex than the "Unit G10 Major Overhaul and Upgrade" project.

Response

a) As noted in Ex. L-H-CCC-03, OPG incorrectly used a Full Execution Business Case Summary as the First Execution Business Case value in Ex. H1-1-1, Table 7b, col. (c), instead of an earlier Partial Execution Business Case Summary. This response explains the statement in OPG's original pre-filed evidence which used the Full Execution Business Case cost estimate.

As discussed in EB-2020-0290, OPG had implemented a number of improvements in the project management function for the Nuclear portfolio since EB-2016-0152. Expanding on these improvements, OPG also began to implement initiatives to enhance project management across the full enterprise, including the Renewable Generation business unit that operates regulated hydroelectric facilities. In the second half of 2020, OPG implemented a major realignment of its organizational structure, which included integration of major project execution groups from across the Nuclear and Renewable Generation business units into the Enterprise Projects Organization, facilitating the implementation of standardized project management tools across the company.[1] The Full Execution Business Case cost estimate for the Unit G5 Major Overhaul project was prepared in 2018, which pre-dated the implementation of the standardized project management tools noted above. Therefore, although characterized as a Class 2 estimate at the time, this cost estimate would be considered a Class 3 estimate under OPG's current project management standards.

b) The in-service date for the project was September 21, 2021.

c) See Chart 1 for the breakdown of project costs for the Unit G5 Major Overhaul.

[1] Details regarding OPG's project management improvement initiatives can be found in EB-2020-0290, Ex. D2-1-1, Section 3.5.

Chart 1

Line Item	Amount ($M)
OPG Labour	
Project Management	0.6
Engineering	1.5
Execution	8.6
OPG Procured Materials	3.8
External	
External Contractor – Execution	27.7
External Contractor – Removal Costs	1.0
Interest	1.5
Total	**44.7**

Note: numbers may not add due to rounding.

d) See Chart 2 for the breakdown of project costs for the Unit G10 Major Overhaul.

Chart 2

Line Item	Amount ($M)
OPG Labour	
Project Management	0.5
Engineering	0.3
Execution	2.0
OPG Procured – Materials	1.5
External	
External Contractor – Execution	24.4
External Contractor – Removal Costs	0.6
Interest	1.5
Total	**30.8**

Note: numbers may not add due to rounding.

e) The execution of the Unit G5 Major Overhaul project was more complex than the Unit G10 Major Overhaul project due to:

i. **Modernization and New Technology Upgrades** – the Unit G5 Major Overhaul implemented a new protection/control and programmable logic controller design and installation, which necessitated extensive development and programming, as well as new condition monitoring instrumentation to enable online monitoring and diagnostics. The Unit G10 Major Overhaul pre-dated these upgrades, which are now being incorporated into overhaul project scope.
ii. **Site Logistics** – the Unit G5 Major Overhaul was executed in parallel with the SAB I Units G1, G2 Replacement project, which required logistical coordination of overhead crane usage that was not necessary during the Unit G10 Major Overhaul.
iii. **Labour Assignment** – the labour assignment for the Unit G5 Major Overhaul was approximately 50% to OPG internal staff, compared to the Unit G10 Major Overhaul being fully contracted. The Unit G5 Major Overhaul represented First-in-a-While work for the station staff, and the experience and learnings from the project will be applied to future overhauls.
iv. **Additional Scope** – the Unit G5 Major Overhaul included a new redesign of the turbine headcover and bottom ring based on condition assessment by Engineering.

Staff Interrogatory #24

Interrogatory

Reference:

Exhibit A1 / Tab 2 / Schedule 1 / pages 1-2

Preamble:

OPG requests approval for “the disposition of audited December 31, 2022 deferral and variance account balances less amortization amounts previously approved by the OEB in EB-2020-0290 for the 2023-2026 period, together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account as set out in Ex. H1-1-1 and Ex. H1-2-1.” OPG states that it seeks to recover the amounts “over a 30-month period from July 1, 2024 through December 31, 2026”.

OPG seeks “payment riders for the output of the regulated hydroelectric facilities of $2.75/MWh for the period from July 1, 2024 to December 31, 2026; and for the output of the nuclear facilities of $3.25/MWh for the period from January 1, 2024 to December 31, 2024, $3.55/MWh for the period from January 1, 2025 to December 31, 2025, and $5.04/MWh for the period from January 1, 2026 to December 31, 2026.”

Question(s):

a) For clarify, does OPG seek to begin recovering the deferral and variance account balances described above through payment riders starting on July 1, 2024 until December 31, 2006?

b) When OPG says that it is seeking payment riders for the output of the nuclear facilities of $3.25/MWh for the period from January 1, 2024 to December 31, 2024, does it mean that the applicable nuclear balances will begin to be collected through payment riders starting on July 1, 2024 until December 31, 2024 but on the basis of nuclear production from January 1, 2024 until December 31, 2024? In other words, is the $3.35/MWh beginning on July 1, 2024 an annualized figure?

Response

a) OPG confirms that it is seeking to recover or repay the deferral and variance account balances requested in this Application through payment riders beginning on July 1, 2024 and ending on December 31, 2026.

b) There is a typographical error in the section referenced in the second paragraph of the preamble (Ex. A1-2-1, p. 2). OPG's proposal is to clear the balances in the nuclear deferral and variance accounts over the period from July 1, 2024 to December 31, 2026, with the proposed payment rider for 2024 applicable to output of the nuclear facilities from July 1, 2024 to December 31, 2024, not from January 1, 2024 to December 31, 2024. The referenced section should read:

> payment riders for the output of the regulated hydroelectric facilities of $2.75/MWh for the period from July 1, 2024 to December 31, 2026; and for the output of the nuclear facilities of $3.25/MWh for the period from **July** 1, 2024 to December 31, 2024, $3.55/MWh for the period from January 1, 2025 to December 31, 2025, and $5.04/MWh for the period from January 1, 2026 to December 31, 2026.

OPG will file an updated version of Ex. A1-2-1, p. 2, reflecting the correction above.

CCC Interrogatory #9

Interrogatory

Reference: Ex. M1/T1/S1

Question:

Please provide all materials provided to Ontario Power Generation's Board of Directors regarding the approvals sought through this Application regarding the Market Renewal program and clearance of the Deferral and Variance Accounts. Please provide all reports produced internally or externally regarding the approvals sought through this Application regarding the Market Renewal Program.

Response

There were no materials provided to OPG's Board of Directors regarding the approvals sought through this Application regarding the IESO's Market Renewal Program and clearance of deferral and variance accounts.

OPG's Enterprise Leadership Team was informed of this Application through the presentation provided in Attachment 1. OPG provided a briefing on this Application to the IESO through the presentation provided in Attachment 2.

No internal or external reports regarding the approvals sought through this Application regarding the IESO's Market Renewal Program were produced.

Impacts of the Market Renewal Program Clearance of Deferral & Variance Accounts

November 2023

Overview

OPG is planning to file an application with the OEB in Q4 2023. The application will address the impacts of the IESO's Market Renewal Program and clearance of deferral and variance account balances.

The following two slides highlight key issues anticipated during the application process.

The remaining slides are from a deck that will be presented to stakeholders in advance of filing the application.

Application Summary and Timing

Deferral & Variance Account Clearance

Impact of the IESO's Market Renewal Program

OPG

Application Summary and Timing

EB-2020-0290 Settlement Agreement

- "OPG shall file an application with the OEB regarding any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP with sufficient time for the OEB to adjudicate the application prior to the scheduled implementation of the MRP."

- "in conjunction with [the MRP] application, or separately during the IR term, OPG may also file an application to clear deferral and variance accounts."

OPG

Application Summary and Timing

In the application, OPG is requesting:

01 Approval for recovery of audited December 31, 2022 balances of regulated hydroelectric and nuclear deferral and variance accounts.

02 Approval of the Surplus Baseload Generation Variance Account spill calculation methodology.

03 Approval of a revised Hydroelectric Incentive Mechanism (“HIM”) methodology and HIM adjustment for spill.

02

Deferral & Variance Account Clearance

Balances & Recovery Periods

- OPG proposes to recover December 31, 2022 D&V account balances for most accounts (less amounts previously approved for recovery through payment riders established in EB-2020-0290)
- Hydroelectric D&V account balances of ~$250M and nuclear D&V account balances of ~$220M
- OPG proposes to clear the recoverable amounts over a 30-month period from July 1, 2024 to December 31, 2026
- Riders concluding at the end of 2026 allows for cleaner transition to rates and riders approved in OPG's next major rate application

02

Hydroelectric D&V Account Balances

De

Regulated Hydroelectric Deferral and Variance Accounts	Audited 2022 Balance ($M)	EB-2020-0290 Amortization ($M)	2022 Balance Less Approved Amortization ($M)
Water Conditions VA	(172.4)	(72.7)	(99.6)
Ancillary Services Net Revenue VA	(34.2)	(22.2)	(12.1)
Hydroelectric Incentive Mechanism VA	0	0	0
Surplus Baseload Generation VA	402.9	112.2	290.6
Income and Other Taxes VA	(13.3)	(1.8)	(11.5)
Capacity Refurbishment VA	83.0	0	83.0
Niagara Tunnel Project 2008 Disallowance VA	8.0	2.5	5.5
Pension & OPEB Cost VA	2.1	2.1	0
Pension & OPEB Cash VA	(77.0)	(25.7)	(51.3)
Pension & OPEB Cash Vs. Accrual Differential DA	110.4	82.3	28.1
Pension & OPEB Forecast Accrual Vs. Actual Cash – Carrying Costs	(2.0)	(0.1)	(1.9)
Hydroelectric Over/Under Recovery VA	16.1	2.3	13.8
Total	**323.5**	**78.9**	**244.5**

OPG

02

Nuclear D&V Account Balances

Nuclear Deferral and Variance Accounts	Audited 2022 Balance ($M)	EB-2020-0290 Amortization ($M)	2022 Balance Less Approved Amortization ($M)
Nuclear Liability DA	188.4	0	188.4
Impact Resulting from Changes in Pickering EOL DAs	(102.4)	(163.9)	61.5
Nuclear Development VA	110.9	2.5	108.4
Ancillary Services Net Revenue VA	(13.6)	(2.4)	(11.3)
Income and Other Taxes VA	(18.8)	(9.7)	(9.1)
Capacity Refurbishment VA	50.7	(76.8)	127.5
Bruce Lease Net Revenues VA	101.3	99.6	1.7
Pension & OPEB Cost VA	(79.6)	42.9	(122.6)
Pension & OPEB Cash VA	(383.4)	(116.1)	(267.3)
Pension & OPEB Cash Vs. Accrual Differential DA	688.3	523.5	164.8
Pension & OPEB Forecast Accrual Vs. Actual Cash – Carrying Costs	(12.3)	(0.4)	(11.9)
Nuclear Over/Under Recovery VA	(74.7)	(16.8)	(58.0)
Fitness for Duty DA	1.6	0	1.6
SR&ED ITC VA	(8.6)	(8.1)	(0.5)
Rate Smoothing DA	568.9	0	568.9
Pickering Closure Costs DA	2.8	0	2.8
Total	**1,019.2**	**274.4**	**744.7**

03

Impact of the IESO's Market Renewal Program

Market Renewal Program Status and Impacts

- IESO is currently in the implementation phase of its Market Renewal Program ("MRP") with an expected in-service date of May 2025.

Impacts of MRP on OPG's regulated framework are primarily due to:

- Replacing the two-schedule market with a single schedule market ("SSM") and locational marginal price ("LMP").
- Introducing a financially binding day-ahead market ("DAM").

03

Impact of the IESO's Market Renewal Program

Overview of OPG's Effective Payment Amounts

- OPG's base payment amounts for the 2022-2026 period were set in EB-2020-0290 for OPG's regulated hydroelectric and nuclear facilities.
- Certain components of OPG's regulatory framework incorporate features of the current two-schedule market, for example the uniform market price.
- Elements of OPG's payment amounts designed on this basis are incompatible with the market post-MRP implementation and will need to be revised to reflect resultant changes and new drivers.

03

Impact of the IESO's Market Renewal Program

MRP Impacts on OPG Regulated Framework Addressed in this Application

MRP Changes		SBGVA	HIM	MWP/CMSC
Single Schedule Market	Uniform price to Locational Prices	☑	☑	
	Eliminate Unconstrained schedule	☑		☑
	Changes to MWP			☑
DAM & RTM	DAM & RTM Settlement		☑	

03

Impact of the IESO's Market Renewal Program

Surplus Baseload Generation Variance Account (SBGVA)

MRP Impact:

1. The calculation of SBG spill amounts will be affected by transition to a single schedule market with the elimination of the uniform market price used in the current SBG spill determination methodology
2. OPG will no longer have access to an indicator of global SBG conditions.

Proposed Treatment:

Revise the calculation of amounts booked in OPG's SBGVA to record the financial impact of forgone production due to SBG conditions based on LMP.

03

Impact of the IESO's Market Renewal Program

HIM Adjustment for SBG ("Unintended Benefit")

MRP Impact:

In alignment with proposed changes to the HIM and calculation of SBG spill, the formula for unintended benefit will be revised accordingly.

Proposed Unintended Benefit Treatment:

A revised unintended benefit formula that incorporates:

- Settlement on real-time LMP. (Due to the real-time nature of spill);
- daily production averaging;

03

Impact of the IESO's Market Renewal Program

Make Whole Payments

MRP Impact:

MRP will introduce changes to the nature and frequency of MWPs. IESO describes MWPs expected post MRP implementation as small and infrequent.

Proposed Treatment:

OPG proposes to retain any real-time MWPs net of any clawbacks, separate from the regulated payment structure consistent with current treatment.

Electrifying life

OPG

Overview of Market Renewal Program and Clearance of Deferral & Variance Accounts Application

OPG IESO meeting

October 24, 2023

Application Summary and Timing

Impact of the IESO's Market Renewal Program

Questions

Application Summary and Timing

EB-2020-0290 Settlement Agreement

- "OPG shall file an application with the OEB regarding any changes to the Hydroelectric Incentive Mechanism and other impacts arising from the MRP with sufficient time for the OEB to adjudicate the application prior to the scheduled implementation of the MRP."

- "in conjunction with [the MRP] application, or separately during the IR term, OPG may also file an application to clear deferral and variance accounts."

- OPG is targeting to file this application by the end of 2023

OPG

Application Summary and Timing

In the application, OPG is requesting:

- Approval of a revised Surplus Baseload Generation Variance Account spill calculation methodology.
- Approval of a revised Hydroelectric Incentive Mechanism ("HIM") methodology and HIM adjustment for spill.
- Approval for recovery of audited December 31, 2022 balances of regulated hydroelectric and nuclear deferral and variance accounts.

02

Impact of the IESO's Market Renewal Program

Market Renewal Program Status and Impacts

- IESO is currently in the implementation phase of its Market Renewal Program ("MRP") with an expected in-service date of May 2025.

Impacts of MRP on OPG's regulated framework are primarily due to:

- Replacing the two-schedule market with a single schedule market ("SSM") and locational marginal price ("LMP").
- Introducing a financially binding day-ahead market ("DAM").

02

Impact of the IESO's Market Renewal Program

Overview of OPG's Effective Payment Amounts

- OPG's base payment amounts for the 2022-2026 period were set in EB-2020-0290 for OPG's regulated hydroelectric and nuclear facilities.
- Certain components of OPG's regulatory framework incorporate features of the current two-schedule market, for example the uniform market price.
- Elements of OPG's payment amounts designed on this basis are incompatible with the market post-MRP implementation and will need to be revised to reflect resultant changes and new drivers.

02

MRP Impacts on OPG Regulated Framework Addressed in this Application

MRP Changes		SBGVA	HIM	MWP/CMSC
Single Schedule Market	Uniform price to Locational Prices	☑	☑	
	Eliminate Unconstrained schedule	☑		☑
	Changes to MWP			☑
DAM & RTM	DAM & RTM Settlement		☑	

02

Surplus Baseload Generation Variance Account (SBGVA)

MRP Impact:

1. The calculation of SBG spill amounts will be affected by transition to a single schedule market with the elimination of the uniform market price used in the current SBG spill determination methodology
2. OPG will no longer have access to an indicator of global SBG conditions.

Proposed Treatment:

Revise the calculation of amounts booked in OPG's SBGVA to record the financial impact of forgone production due to SBG conditions based on LMP.

OPG

02

Hydroelectric Incentive Mechanism (HIM)

MRP Impact:

The HIM needs to be revised to reflect new market features including LMP and settlement of the new day-ahead and real-time markets.

Proposed HIM Treatment:

A revised Hydroelectric Incentive Mechanism to incorporate:

- separate incentives for the day-ahead and real-time timeframe;
- settlement on LMP;
- daily production averaging instead of the current monthly production averaging.

OPG

02

HIM Adjustment for SBG ("Unintended Benefit")

MRP Impact:

In alignment with proposed changes to the HIM and calculation of SBG spill, the formula for unintended benefit will be revised accordingly.

Proposed Unintended Benefit Treatment:

A revised unintended benefit formula that incorporates:

- Settlement on real-time LMP. (Due to the real-time nature of spill);
- daily production averaging;

OPG

02

Make Whole Payments

MRP Impact:

MRP will introduce changes to the nature and frequency of MWPs. IESO describes MWPs expected post MRP implementation as small and infrequent.

Proposed Treatment:

OPG proposes to retain any real-time MWPs net of any clawbacks, separate from the regulated payment structure consistent with current treatment.

03

Questions

Electrifying life

OPG

CCMBC Interrogatory #1

Interrogatory

Reference: Exhibit A1, Tab 2, Schedule 1, Page 1

Preamble: "In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the Ontario Energy Board Act, 1998 (the "Act"), for:

(i) an order or orders approving changes to the calculation of amounts for the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") and the Hydroelectric Incentive Mechanism ("HIM"), and approving the treatment of real time make whole payments, resulting from the implementation of the Independent Electricity System Operator's ("IESO") Market Renewal Program ("MRP");"

Questions:

a) What is the latest effective date for the order or orders mentioned in (i) above in the quoted text?

b) Please explain why orders are needed by the date provided in response to question (b)?

c) What would happen if the OEB did not issue the orders by that date?

Response

OPG interprets parts a), b) and c) to be referring to the effective date of the OEB's order(s) and not the date the order(s) is issued and has responded accordingly. With respect to the date that the OEB order(s) is issued, OPG believes a date that is at least 6 months in advance of the IESO Market Renewal Program ("MRP") implementation date is necessary to allow sufficient time for OPG and the IESO to operationalize the order in their respective settlement systems.

a) As discussed in Ex. L-M-Staff-25, OPG proposes an implementation date (i.e., effective date) for the order(s) that aligns with the IESO MRP implementation date, currently targeted for May 1, 2025.

b) and c)

The OEB's order is the instrument instructing the IESO in its settlement of OPG's regulated facilities. Absent alignment of the effective date for the OEB order(s) and the MRP implementation date, the IESO will not have all necessary instruction to settle OPG's generation in the new market. Additionally, OPG's existing ratemaking methodologies related to production from its prescribed hydroelectric generating facilities would not compensate the company for certain changes associated with the new market design, causing insufficient revenue recovery. As well, the incongruence of the existing HIM with the new market design would affect market-based incentives for OPG's regulated hydroelectric generation in the absence of the OEB's order addressing this issue.

CCMBC Interrogatory #4

Interrogatory

Reference: Exhibit M1, Tab 1, Schedule 1, Page 1

Preamble: "In this application, OPG is requesting approvals in three areas based on expected changes to Ontario's electricity market that will be made under the Independent Electricity System Operator's ("IESO") Market Renewal Program ("MRP"). Specifically, OPG proposes:

i. changes to the calculation of amounts for the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA"),
ii. changes to the Hydroelectric Incentive Mechanism ("HIM"), and
iii. to establish a treatment for real-time make whole payments ("MWP")."

Questions:

Please provide the schedule and the cost estimate for the implementation of each of the following three changes:

a) changes to the calculation of amounts for the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA"),

b) changes to the Hydroelectric Incentive Mechanism ("HIM"), and

c) to establish a treatment for real-time, make whole payments ("MWP")."

d) Will commercial operations of OPG's unregulated hydroelectric stations be affected by the MRP?

e) Do OPG staff involved in the commercial operations of regulated OPG hydro-electric stations have any responsibilities in the commercial operations of unregulated OPG hydro-electric stations? If the answer is yes, please discuss how OPG ensures that there is no inappropriate use of information obtained from commercial operations of regulated stations.

Response

a) to c)

With respect to schedule, OPG is unable to provide the requested information. OPG expects that the schedule for the implementation of any changes approved in this Application would be dependent on the schedule for the IESO's implementation of the Market Renewal Program. As further discussed in Ex. L-M-Staff-25, OPG is proposing that the changes be implemented on the date of the IESO's Market Renewal Program implementation.

With respect to costs, OPG declines to provide the requested information on the basis of relevance. OPG's Application is based on the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. OPG is not seeking any costs associated with implementing these changes in this Application.

d) OPG declines to provide the requested information on the basis of relevance. OPG's Application is based on the amounts OPG proposes to clear from the previously authorized deferral and variance accounts and certain specific approvals sought in connection with the implementation of the IESO's Market Renewal Program. These questions regarding OPG's unregulated hydroelectric stations do not seek information that is relevant to any issue before the OEB in the current application.

e) OPG is the registered market participant with the IESO for both the regulated and unregulated hydroelectric facilities. As such, OPG can submit dispatch data for both. OPG's regulated and unregulated facilities are subject to the same Market Rules. There are no regulatory, contractual or market rules that prevent OPG from sharing information between the segments.

CCMBC Interrogatory #5

Interrogatory

Reference: M1-Tab 1, Schedule 1, Page 10

Preamble: "The remaining spill volume would be identified as potential SBG spill. SBG conditions would be considered to be present when the applicable RT LMP for the resource as published by the IESO falls below the applicable GRC price threshold."

Questions:

a) How many hydroelectric stations does OPG operate, and will each station have its own RT LMP published by the IESO? Please explain your answer.

b) When would the IESO publish the RT LMP for each station? Will it be in real time or at some other frequency?

c) Please file numerical examples of the existing and proposed Spill Calculation methods. Please show all units and indicate sources of inputs.

Response

a) OPG operates 66 regulated and unregulated hydroelectric stations, of which all non-embedded hydroelectric stations' associated resource(s) will have their own RT LMP(s) for their respective price node(s). Please refer to Ex. L-M-Staff-11, part e) for further information.

b) After each five-minute interval, the IESO would publish RT LMPs "as soon as practicable after the real-time calculation engine produces valid results".[1]

c) The proposed SBG spill calculation methodology makes two changes to the existing methodology as a result of the Market Renewal Program: Market constraints are not applicable in the calculation of the potential SBG spill, and potential SBG spill would be evaluated against each resource's RT LMP, rather than HOEP. Chart 1 provides an illustrative, numerical example to compare OPG's existing and proposed methodology for calculating potential SBG spill. Under both methodologies, potential SBG spill would be calculated hourly and evaluated

[1] MRP Market Rule Chapter 7, IESO, March 13, 2024, Section 6.6.1. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/mr-00454-r00-mso-ch7-system-operations-and-physical-markets-20240313.pdf

against the applicable market prices throughout the day. All inputs in the example are assumed, and logic is provided where calculations are applied.
For clarity, the illustration is not intended to be indicative of the relative magnitude of changes in SBG spill quantities between the current market design under the existing methodology and the new market design under the proposed methodology. As discussed in Ex. L-M-Staff-23, the proposed changes to the SBGVA to include local SBG-related spill will increase the types of spill considered under the SBGVA. However, the IESO expects that the market structure under Market Renewal will provide new efficiencies in the market that will result in reduced curtailment and spilling of water.[2]

Chart 1: Illustrative SBG Spill Calculation

Existing Method			Proposed Method		
Value	**Logic**	**Parameter**	**Logic**	**Value**	**Source**
0.75	(a)	Efficiency Factor (MWh/cms)	(a)	0.75	Based on flow and unit data
200	(b)	Total Spill (cms)	(b)	200	Hourly volume of spill as reported by regional control centers
150	(c) = (a) x (b)	Total Spill (MWh)	(c) = (a) x (b)	150	Calculated
N/A	(d)	Conveyance Constraints (cms)	(d)	N/A	Based on actual water elevations. This category is only applicable for Sir Adam Beck
110	(e)	Production capability (MWh)	(e)	110	Station generating capability adjusted for outages and operating restrictions
110	(f) = minimum of (d) x (a) or (e)	Available capacity (MWh)	(f) = minimum of (d) x (a) or (e)	110	Calculated
30	(g)	Actual Production (MWh)	(g)	30	Metered generation
80	(h) = (f) - (g)	Spare capacity (MWh)	(h) = (f) - (g)	80	Calculated
80	(i) = minimum of (c) or (h)	Market Spill (MWh)	(i) = minimum of (c) or (h)	80	Calculated
30	(j)	Market constraints (MWh)	N/A	N/A	IESO unconstrained and constrained schedule reports
10	(k)	Contractual obligations (MWh)	(k)	10	IESO energy dispatch and metered production
40	(l) = (i) - (j) - (k)	Potential SBG spill (MWh)	(l) = (i) - (k)	70	Calculated

Units: cms – cubic meters per second, MWh – megawatt hours

[2] Market Renewal Program Energy Stream Business Case, IESO, October 22, 2019, s. 3.6. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf

CCMBC Interrogatory #6

Interrogatory

Reference: M1-Tab 1, Schedule 1, Page 11

Preamble: "The HIM supports the efficiency of the wholesale electricity market by providing OPG's regulated hydroelectric generators with the appropriate drivers to follow market signals while receiving a regulated payment for its output. This mechanism ultimately benefits customers by creating an economic driver for OPG to shift hydroelectric generation from low-price hours to high-price hours."

Questions:

a) Since OPG's regulated hydroelectric generators constitute a large portion of the market, would the shifting of hydroelectric generation from low-price hours to high-price hours increase the market price during the low-price hours?

b) How would customers who are taking advantage of the low-price hours to charge EV's and batteries for emergency power benefit if the price during the low-price hours were to increase?

Response

a) Shifting of hydroelectric generation from low-price hours to high-price hours will increase the market price during the low-price hours, while lowering the price during high price hours. This is beneficial for customers as the total customer cost savings are mainly attributable to the ability to shift lower priced generation in the off-peak to offset more expensive generation in the high-priced on-peak hours.

b) Customers who leverage low price time-of-use rates to charge their EVs or batteries do so through the OEB's Time-of-Use or Ultra-low Overnight price periods and are not directly impacted by the market clearing price each hour. OPG's lowering of system costs will ultimately flow to all customers.

CCMBC Interrogatory #7

Interrogatory

References: Exhibit M1, Tab 1, Schedule 1, Pages 12 to 14; Chart 1, Pages 19 and 20

Questions:

a) Please file a numerical example of the calculation of HIM using the current HIM formula. Please show all units and indicate sources of inputs.

b) Please file a numerical example the calculation of HIM using the proposed HIM formula. Please show all units and indicate sources of inputs.

Response

This response provides an illustrative numerical example of the calculation for the current and proposed HIM, as well as for the Adjustment for Unintended Benefit requested in Ex. L-M-CCMBC-8.

In order to provide this illustrative example, OPG has made the following assumptions:

- Chart 1 (Current HIM formula): Demonstrates the benefits of shifting generation from a low-price hour (A) to a high price hour (B) in the real-time market.
- Chart 2 (Proposed HIM formula): Demonstrates the benefits of shifting generation from a low-price hour (A) to a high price hour (B) in the day-ahead market. In the real-time market, the example demonstrates the interplay between the day-ahead and real-time markets where the real-time price has increased in comparison to the day-ahead price.

Chart 1: Illustrative Example for 2 Hours of Current HIM Calculation Including Adjustment for Unintended Benefit

Hour	Real-time Price	Real-Time Output	SBG Spill	Monthly Avg. Real-Time Output	Monthly Avg. SBG Spill	HIM Payment	Adjustment for Unintended Benefit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	$5/MWh	0MW	60	60MW	5MW	$(300)	$275
B	$40/MWh	300MW	0	60MW	5MW	$9,600	$(200)

Sources for actual monthly calculation:

(a) Published in IESO reports
(b) OPG revenue meter data (utilized in settlement statements)
(c) Per OEB approved SBG methodology
(d) Monthly simple average of (b) for all hours in the month
(e) Monthly simple average of (c) for all hours in the month
(f) Calculated as: (b-d)*a
(g) Calculated as: (c-e)*a

Chart 2: Illustrative Example for 2 hours of Proposed HIM Calculation Including Adjustment for Unintended Benefit

Hour	Day-ahead Price	Day-ahead Schedule	Real-time Price	Real-time Output	SBG Spill	Daily Avg. Day-ahead Dispatch	Daily Avg. Real-time Output	Daily Avg. SBG Spill	Day-ahead HIM Payment	Real-time HIM Payment	Adjustment for Unintended Benefit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
A	$5/MWh	0MW	$5/MWh	0MW	60	80MW	85MW	10MW	$(400)	$(25)	$250
B	$30/MWh	300MW	$40/MWh	300MW	0	80MW	85MW	10MW	$6,600	$(200)	$(400)

Sources for actual monthly calculation:

(a) Published in IESO reports
(b) Published in IESO reports
(c) Published in IESO reports
(d) OPG revenue meter data (utilized in settlement statements)
(e) Per OEB approved SBG methodology
(f) Daily simple average of (b) for all hours of the day
(g) Daily simple average of (d) for all hours of the day
(h) Daily simple average of (e) for all hours of the day
(i) Calculated as: (b-f)*a
(j) Calculated as: [(d-b)-(g-f)]*c
(k) Calculated as: (e-h)*c

CCMBC Interrogatory #8

Interrogatory

Reference: Exhibit M1, Tab 1, Schedule 1, Pages 17 and 18; Chart 1, Page 20

Questions:

a) Please file a numerical example of the calculation of Unintended Benefit Adjustment using the current formula. Please show all units and indicate sources of inputs.

b) Please file a numerical example of the calculation of Unintended Benefit Adjustment using the proposed formula. Please show all units and indicate sources of inputs.

Response

Refer to Ex. L-M-CCMBC-07.

ED Interrogatory #10

Interrogatory

Reference: Exhibit M1

Questions:

(a) Please describe the likely impacts of the changes to the proposed SBGVA and HIMVA on the quantity of spilling (MWh) versus the status quo.
(b) Please provide a description of all options considered by OPG for revising the SBGVA and HIMVA, along with the pros and cons of each.
(c) Please disclosure all internal OPG analysis, presentations, or other similar such documents describing and assessing different options for revising the SBGVA and HIMVA.

Response

a) See Ex. L-M-Staff-23 related to impacts of the proposed changes to the SBGVA.

OPG has not proposed a change to the HIMVA.

b) OPG has not proposed changes to the HIMVA. OPG considered two additional methods for revising the SBGVA outlined below.

OPG considered an alternative method to recover global SBG-related spill amounts by using the system reference bus price (Richview Bus) instead of the unconstrained price. This option was rejected for the following reasons:

i. OPG determined that the energy component of the reference bus price is not a valid indicator of unconstrained conditions.
ii. Using statistical analysis, OPG determined that the unconstrained price and the Richview bus price are not well correlated.
iii. OPG also determined that even if the reference bus price was a suitable replacement for the unconstrained price, OPG will be unable to identify spill related to system constraints in the new market. Resultantly, OPG would be unable to remove system constraint spill from the spill booked in the SBGVA as it does currently.

Secondly, OPG explored the use of a mathematical model that allocates total spill quantities to "constrained spill" and "SBG spill" based on historical statistical trends. This option was rejected for the following reasons:

i. OPG determined that existing data used to calibrate the model is only available in the current market.
ii. The approach ignores expected new market efficiencies expected to reduce spill amounts as discussed in part a).

Ultimately, OPG deemed the proposal described in this application as the most appropriate method to address changes in the new market.

c) OPG has not proposed changes to the HIMVA. Attachment 1 is a presentation summarizing Option 1 in part b). Attachment 2 is a presentation summarizing Option 2 in part b).

Estimation of Constrained-Off Quantity

Model Development and Analytics | October 2021

ONTARIO POWER GENERATION

Spill Allocation

Total Spill

- **Capacity Spill**
  $Q_{SP} > Q_{MAX} - \min(Q_{ACTUAL}, Q_{CONS})$
- **Market Spill**
  $Q_{SP} \leq Q_{MAX} - \min(Q_{ACTUAL}, Q_{CONS})$
  - **Constraint Spill**
    $Q_{SP} \leq \max(Q_{UNCONS} - Q_{CONS}, 0)$
  - **Possible SBG Spill**
    $Q_{SP} > \max(Q_{UNCONS} - Q_{CONS}, 0)$
    - **SBG Spill**
      $P_{MCP} \leq P_{GRC}$
    - **Unknown Spill**
      $P_{MCP} > P_{GRC}$

Q_{UNCONS}=?
P_{MCP}=?

DRAFT

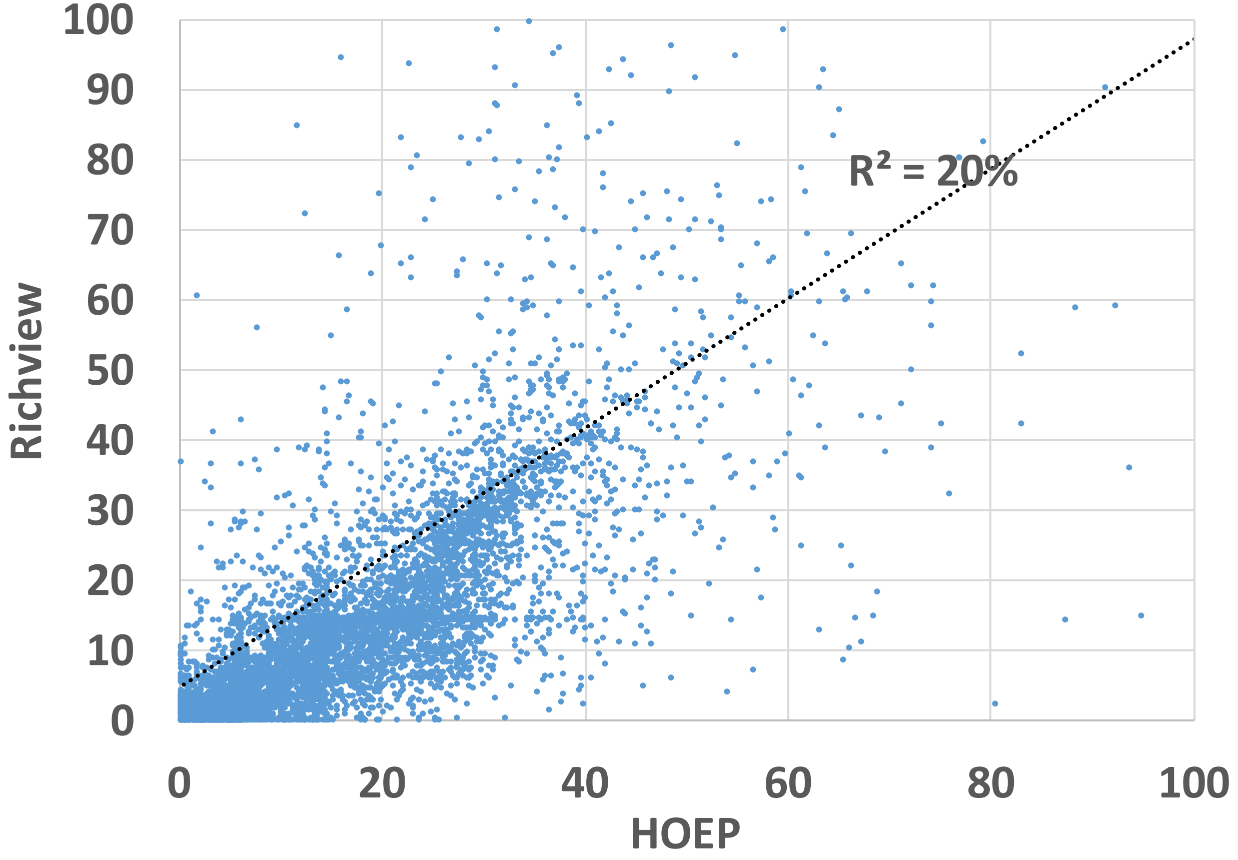
Estimating Unconstrained Dispatch

- Assume we know energy offers (P_i, Q_i) and unconstrained MCP
- Using stack-and-cut would give

$$U = \sum(Q_i, Pi < MCP) + \frac{1}{2}\sum(Qi, Pi = MCP)$$

- This ignores joint optimization with OR, ramp rates, and other constraints
- Also, we don't have unconstrained MCP after Market Renewal!
- Possible proxies for unconstrained MCP:
  - Reference node (Richview) LMP
  - Weighed average of all nodal LMP's

Correlation of HOEP and Richview Energy Price (2016-2020)

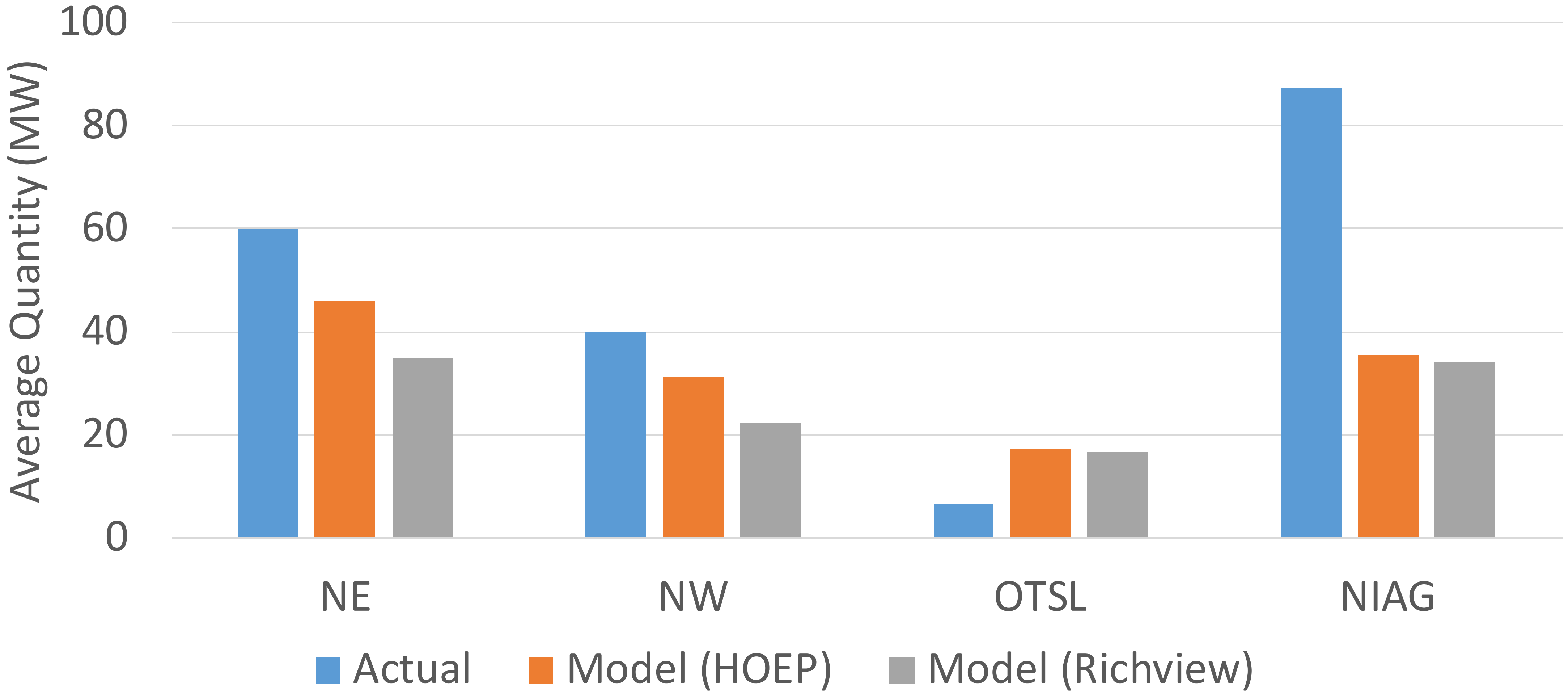


DRAFT

Estimating Unconstrained Dispatch (cont.)

- Load all hydro energy offers for 2016-2020
- Load all RT prices (energy MCP and Richview shadow prices)
- Calculate constrained-off quantity in 3 ways:
    1. Actuals: max (unconstrained – constrained, 0)
    2. Model HOEP (stack-and-cut using HOEP)
    3. Model Reference (stack and cut using Richview)

Constrained-off Quantity by Plant Group



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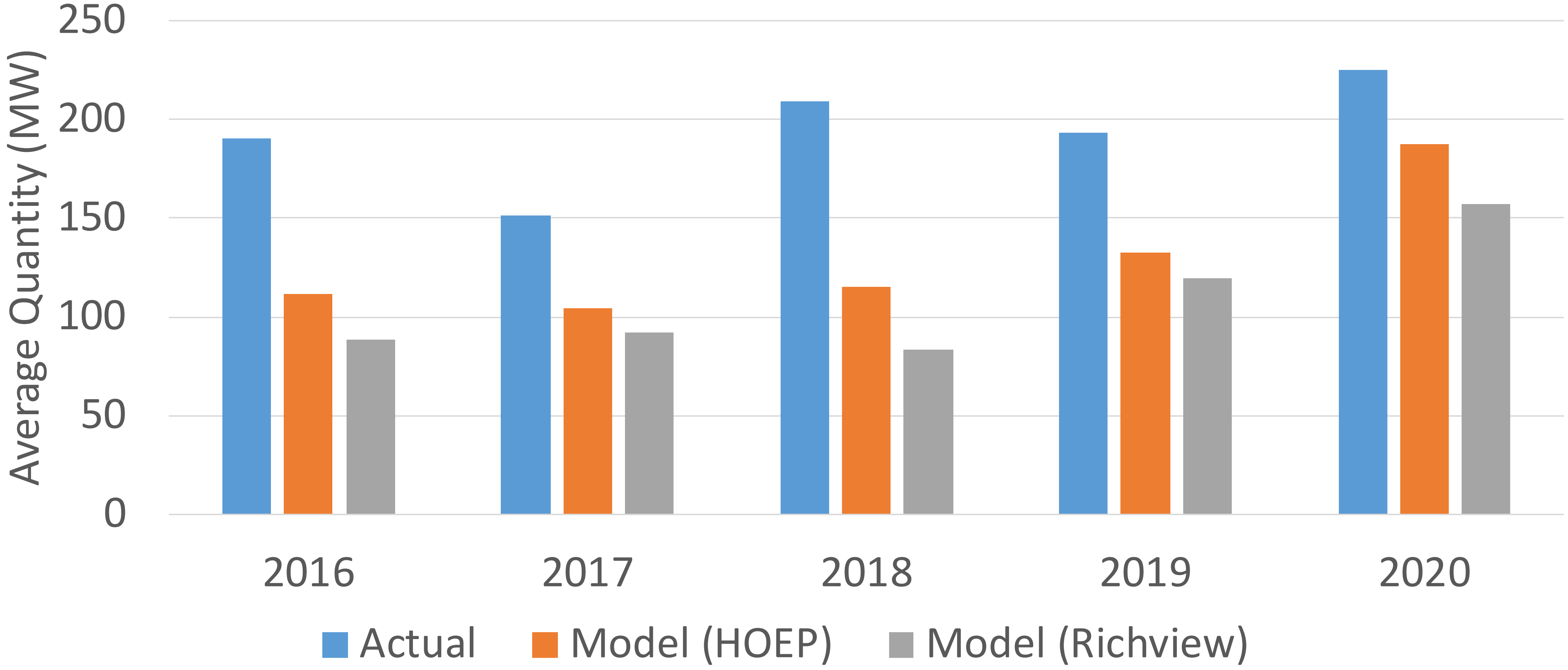
Constrained-off Quantity by Year



DRAFT

SBG Spill Allocation after Market Renewal

Model Development and Analytics | January 2022

ONTARIO POWER GENERATION

Spill Allocation (current)

Total Spill

Capacity Spill

$Q_{SP} > Q_{MAX} - \min(Q_{ACTUAL}, Q_{CONS})$

Market Spill

$Q_{SP} \leq Q_{MAX} - \min(Q_{ACTUAL}, Q_{CONS})$

Constraint Spill

$Q_{SP} \leq \max(Q_{UNCONS} - Q_{CONS}, 0)$

Possible SBG Spill

$Q_{SP} > \max(Q_{UNCONS} - Q_{CONS}, 0)$

SBG Spill

$P_{MCP} \leq P_{GRC}$

Unknown Spill

$P_{MCP} > P_{GRC}$

$Q_{UNCONS}=?$

$P_{MCP}=?$

Spill Allocation Problem (post-MR)

Given only the following quantities:

- Station Locational Marginal Cost (LMP)
- Station Marginal Cost of Congestion (MCC)
- Reference LMP at Richview bus (ENGY)
- Station Gross Revenue Charge (GRC)
- Station market spill (total spill – capacity spill)

Decompose market spill into constrained-off, SBG, and unknown spill.

Methodology

Set

- ConstrainedSpill = c * MarketSpill
- SbgSpill = s * MarketSpill
- UnknownSpill = u * MarketSpill

where c, s, and u are weighing factors in interval [0, 1] with

$$c + s + u = 1$$

and where c, s, and u depend on the following 2 conditions:

- Is MCC < 0 or is MCC >= 0?
- Is ENGY <= GRC or is ENGY > GRC?

Weights **should** depend on MCC, ENGY and GRC as follows :

ENGY Condition	MCC Condition	ConsOff Multiplier	SBG Multiplier	Unknown Multiplier
ENGY <= GRC	MCC < 0	c1	s1	1-c1-s1
ENGY <= GRC	MCC >= 0	**0**	s2	1-s2
ENGY > GRC	MCC < 0	c3	**0**	1-c3
ENGY > GRC	MCC >= 0	**0**	**0**	1

Details of Calibration

M = actual hourly market spill

C_M, S_M, U_M = model hourly constrained-off, SBG, and unknown spill

I_1 = set of hours with ENGY $\leq$ GRC and MCC < 0

I_2 = set of hours with ENGY $\leq$ GRC and MCC ≥ 0

I_3 = set of hours with ENGY $>$ GRC and MCC < 0

I_4 = set of hours with ENGY $>$ GRC and MCC ≥ 0

$C_M = c_1\, M(I_1) + c_2\, M(I_2) + c_3\, M(I_3) + c_4\, M(I_4)$

$S_M = s_1\, M(I_1) + s_2\, M(I_2) + s_3\, M(I_3) + s_4\, M(I_4)$

$U_M = u_1\, M(I_1) + u_2\, M(I_2) + u_3\, M(I_3) + u_4\, M(I_4)$

Details of Calibration (continued)

C_A, S_A, U_A = actual hourly constrained-off, SBG, and unknown spill

θ_{HM} = hourly-to-monthly averaging operator

Choose a fixed historical calibration period P

Minimize

$$\text{sum}\Big((\theta_{HM}(C_M - C_A))^2 + (\theta_{HM}(S_M - S_A))^2 + (\theta_{HM}(U_M - U_A))^2 \text{ , t in P}\Big)$$

Subject To

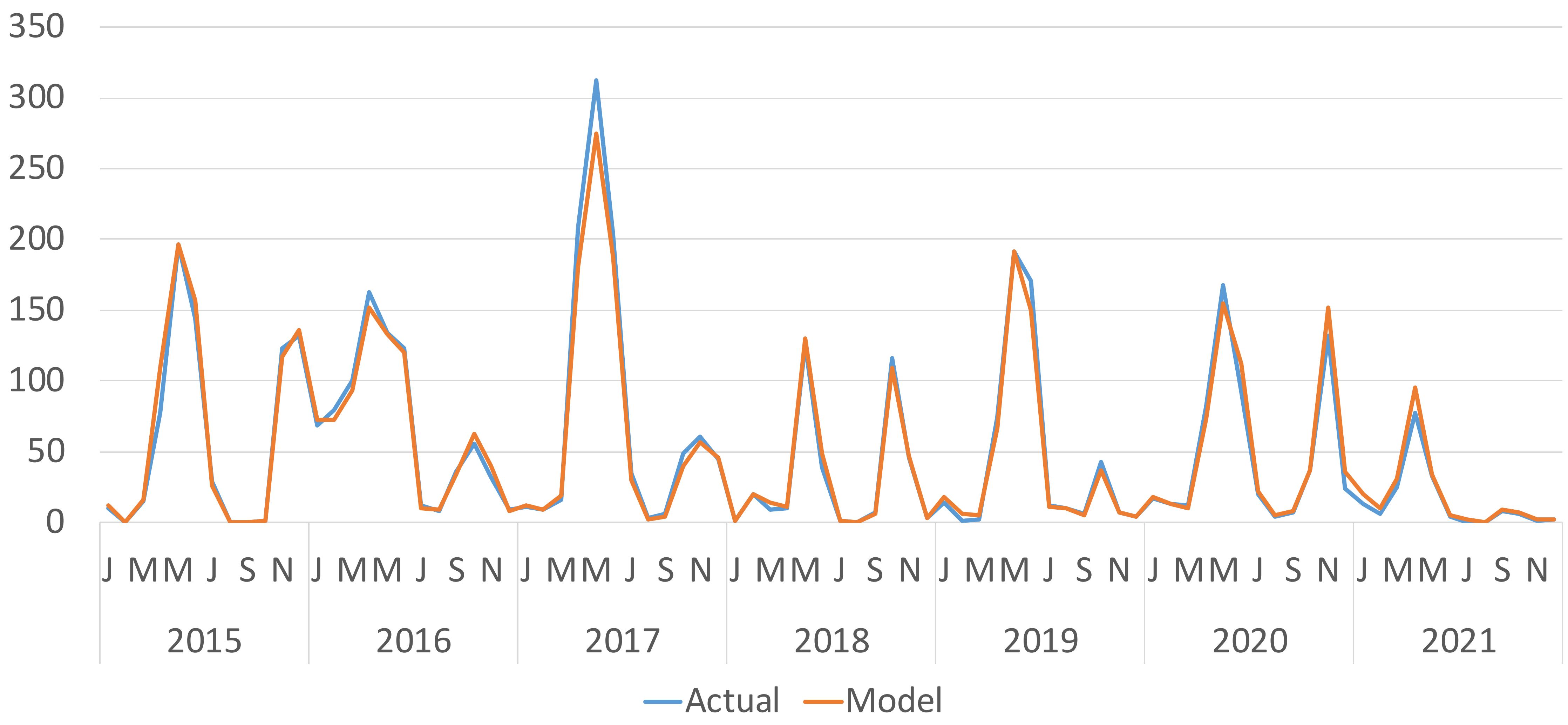
$$0 \le c_i, s_i, u_i \le 1, \qquad \sum c_i = 1, \qquad \sum s_i = 1, \qquad \sum u_i = 1$$

This is a linearly-constrained quadratic minimization problem which Matlab's quadprog function can solve.

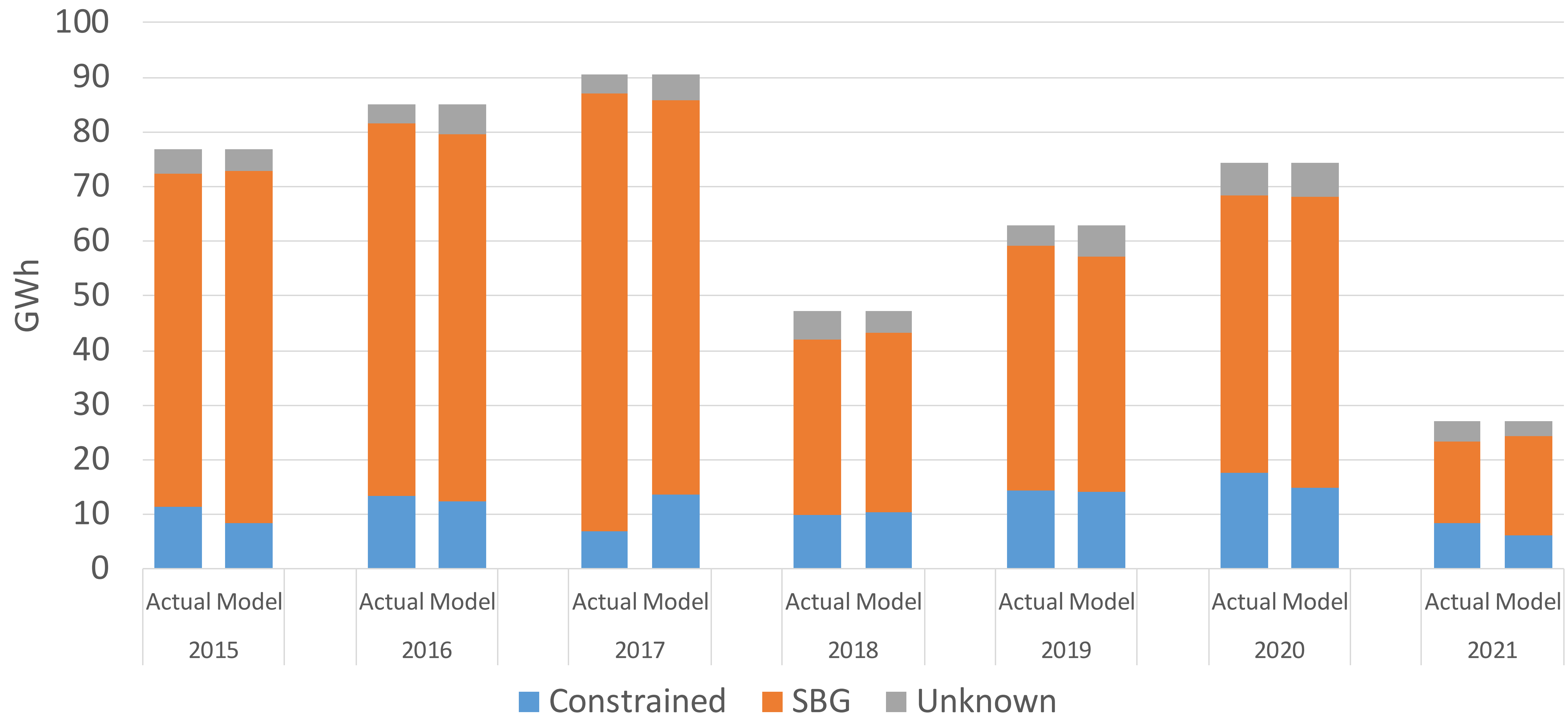
Results for Abitibi (Calibrated from 2015-2020)

		ConsOff Multiplier	SBG Multiplier	Unknown Multiplier
ENGY <= GRC	MCC < 0	0.0051	0.9783	0.0166
ENGY <= GRC	MCC >= 0	**0.1066**	0.8580	0.0354
ENGY > GRC	MCC < 0	0.7819	**0**	0.2181
ENGY > GRC	MCC >= 0	**0.6153**	**0**	0.3847

Monthly SBG Spill for Abitibi (GWh)



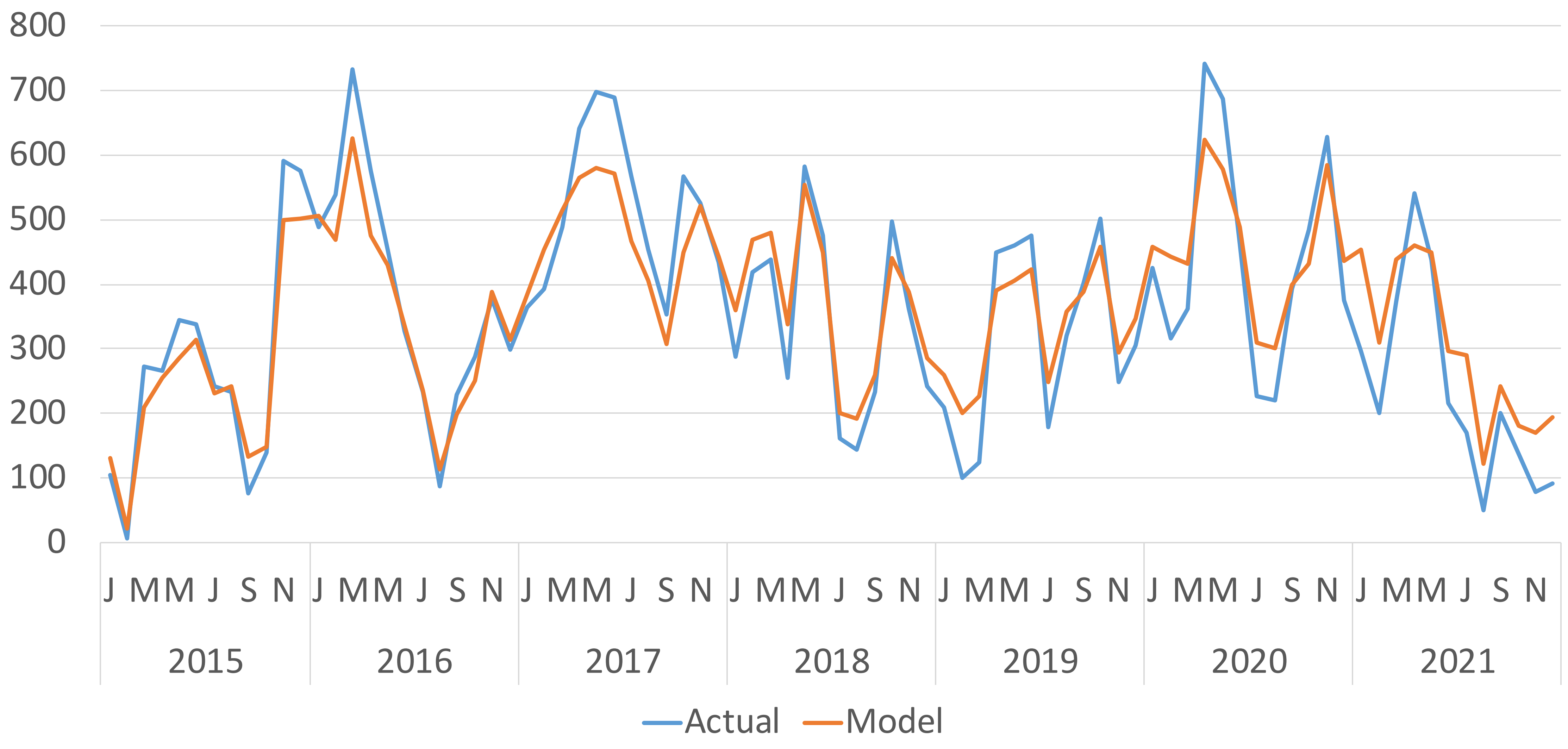
Abitibi Spill Allocation by Year



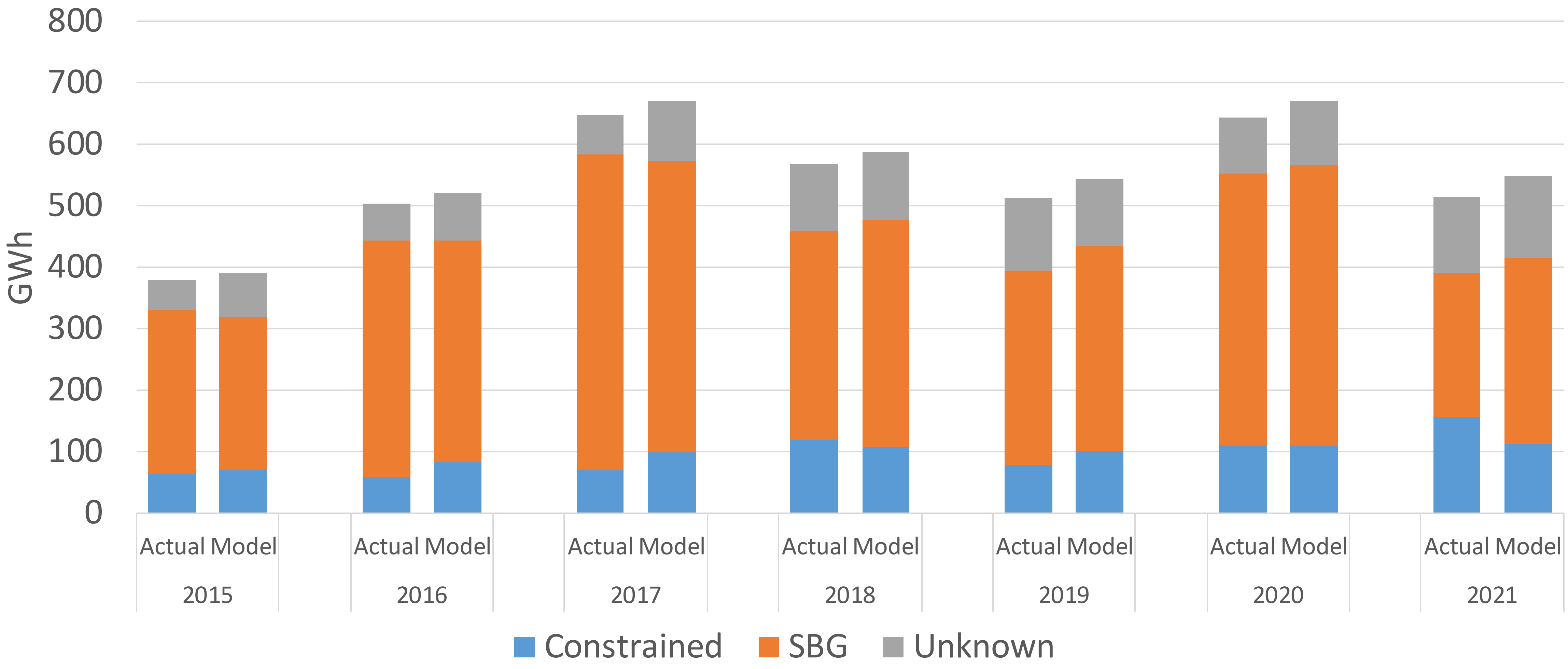
Results for Beck (Calibrated from 2015-2020)

		ConsOff Multiplier	SBG Multiplier	Unknown Multiplier
ENGY <= GRC	MCC < 0	0.0494	0.9175	0.0330
ENGY <= GRC	MCC >= 0	**0.1406**	0.7679	0.0915
ENGY > GRC	MCC < 0	0.4432	**0**	0.5568
ENGY > GRC	MCC >= 0	**0.3653**	**0**	0.6347

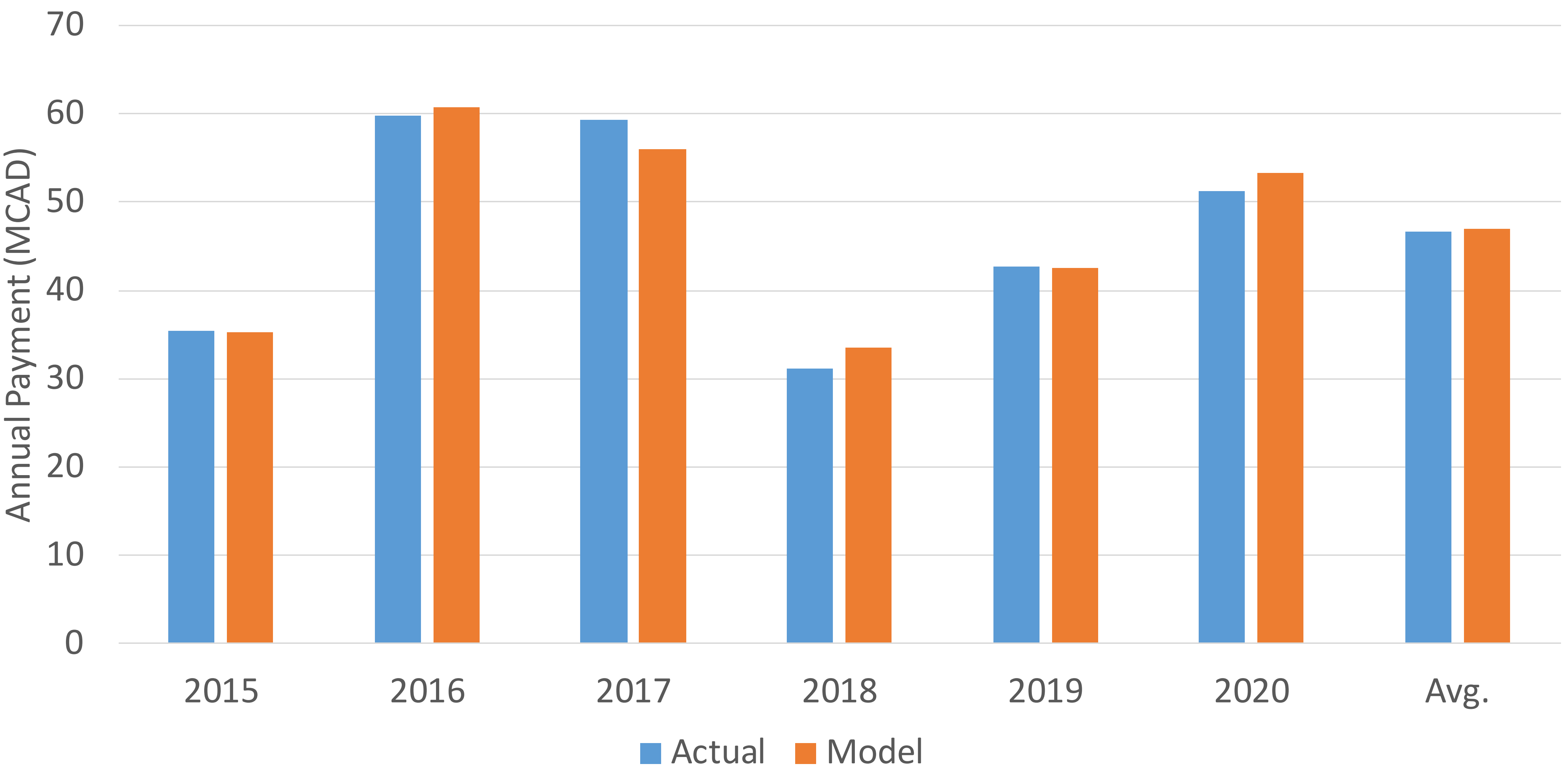
Monthly SBG Spill for Beck (GWh)



Spill Allocation by Year for Beck



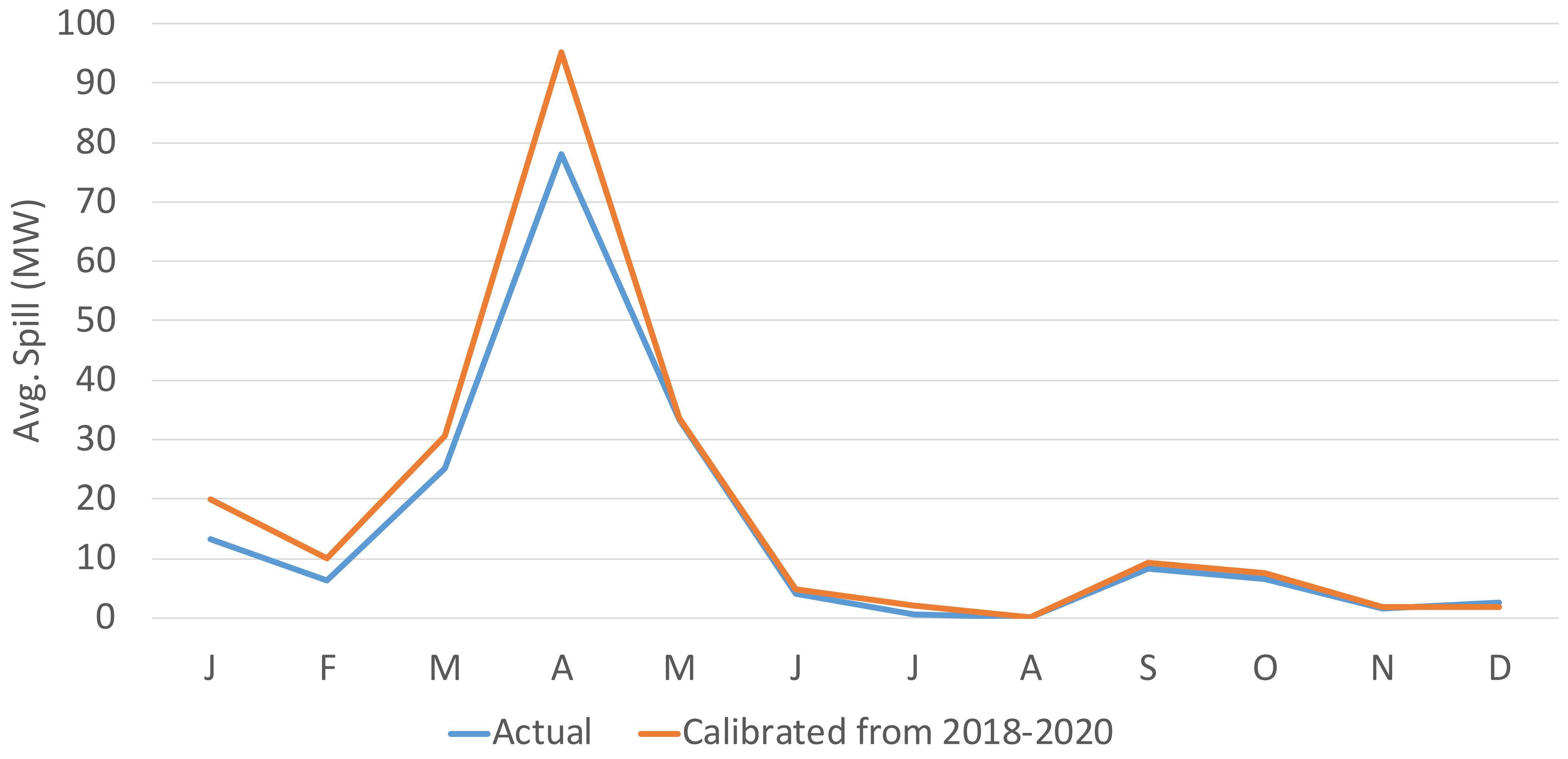
Annual non-Beck SBG Variance Payments (2015-2020)



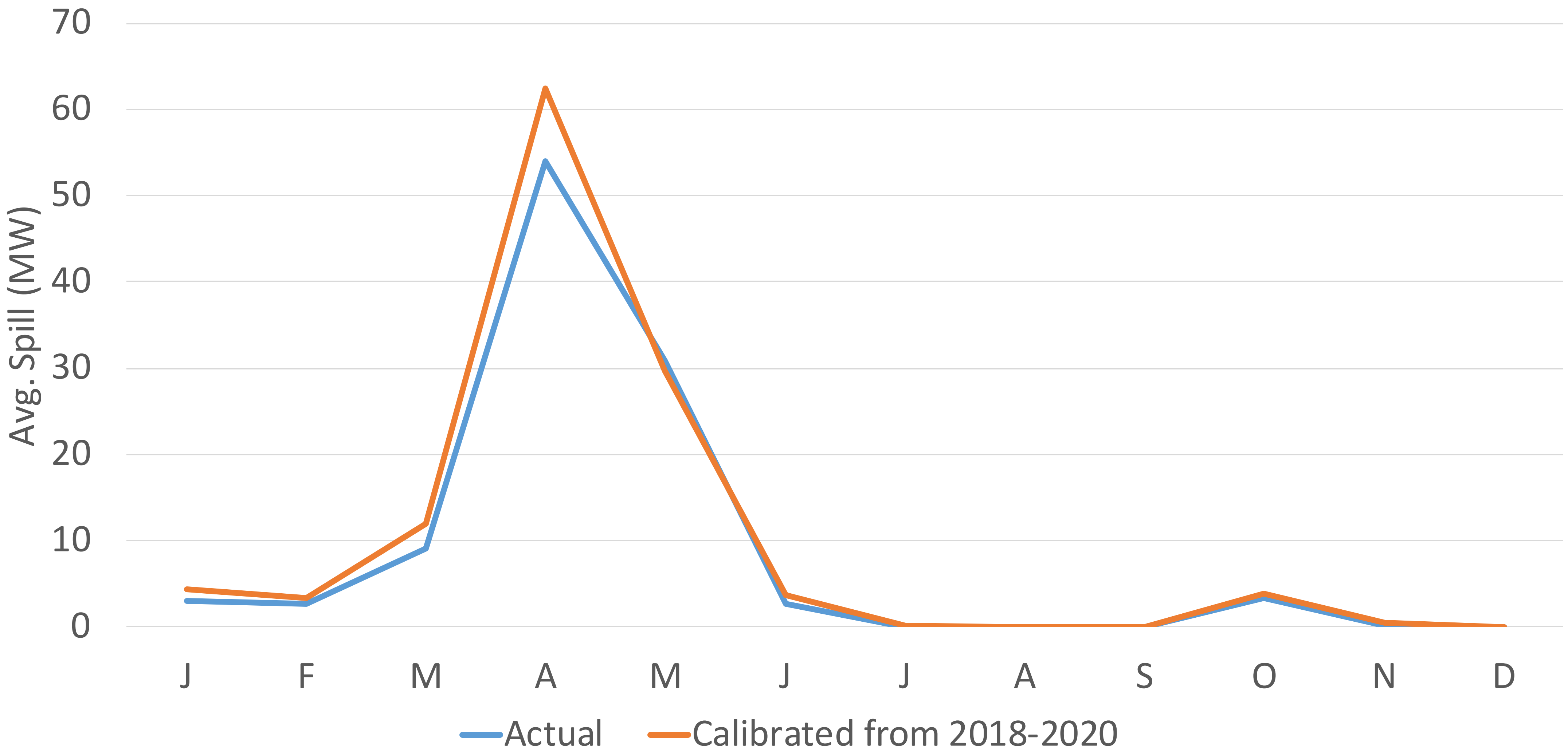
Proposed Methodology

- Assume that the proposed spill factors would be used in the period from 2024 to 2026 (beginning of market renewal until recalculation of hydro regulated rates).
- We would calibrate them from a fixed pre-MR period for which actual SBG spill allocation is known.
- For example, using actual spill allocation from 2021 to 2023 would make sense (use 3-year calibration period to calculate factors for 3-year simulation period).
- To test the effectiveness of this strategy we calibrate factors from 2018-2020 data and compare the modelled 2021 values with the actual 2021 values.

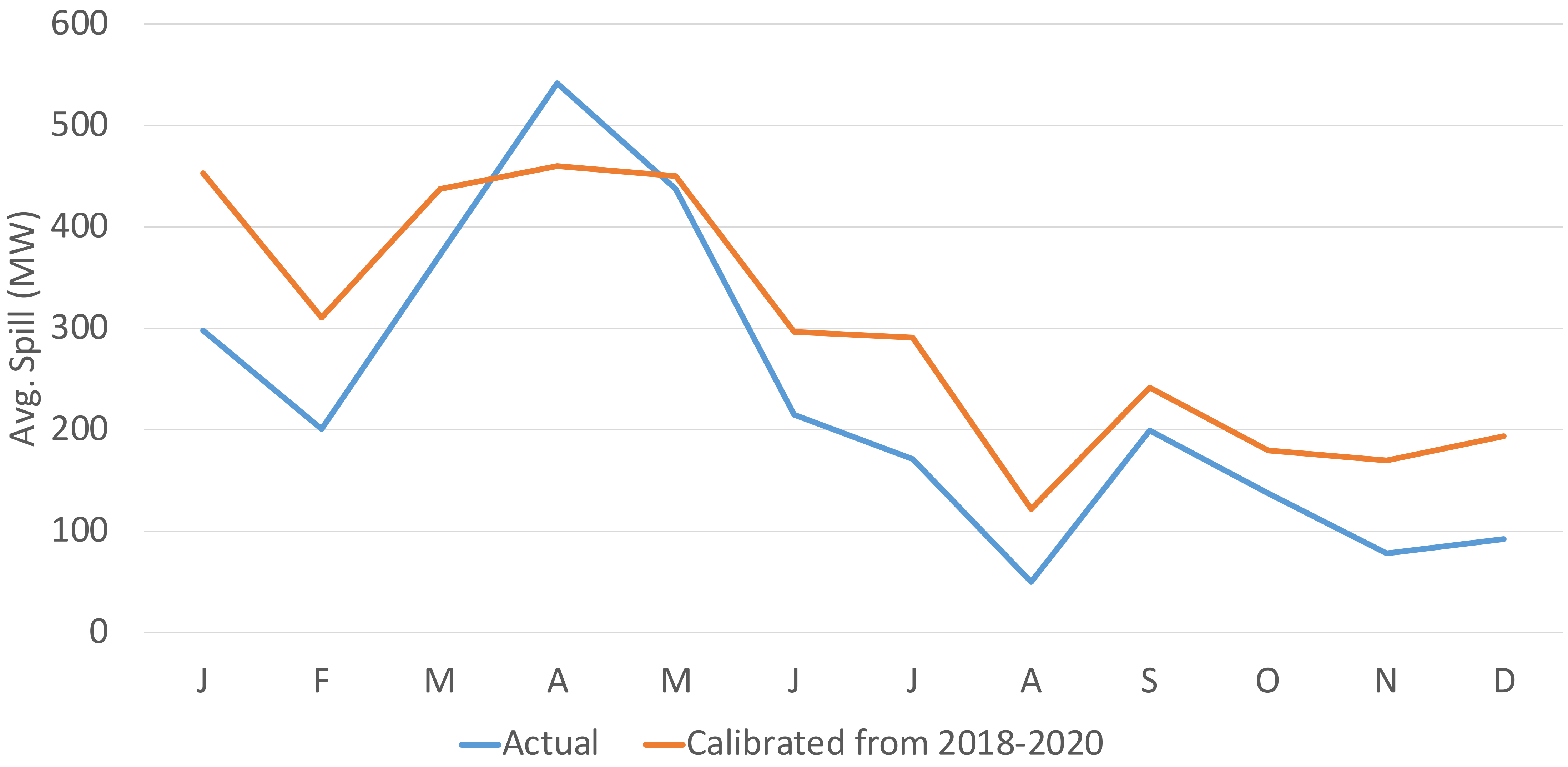
Monthly Abitibi SBG Spill (2021)

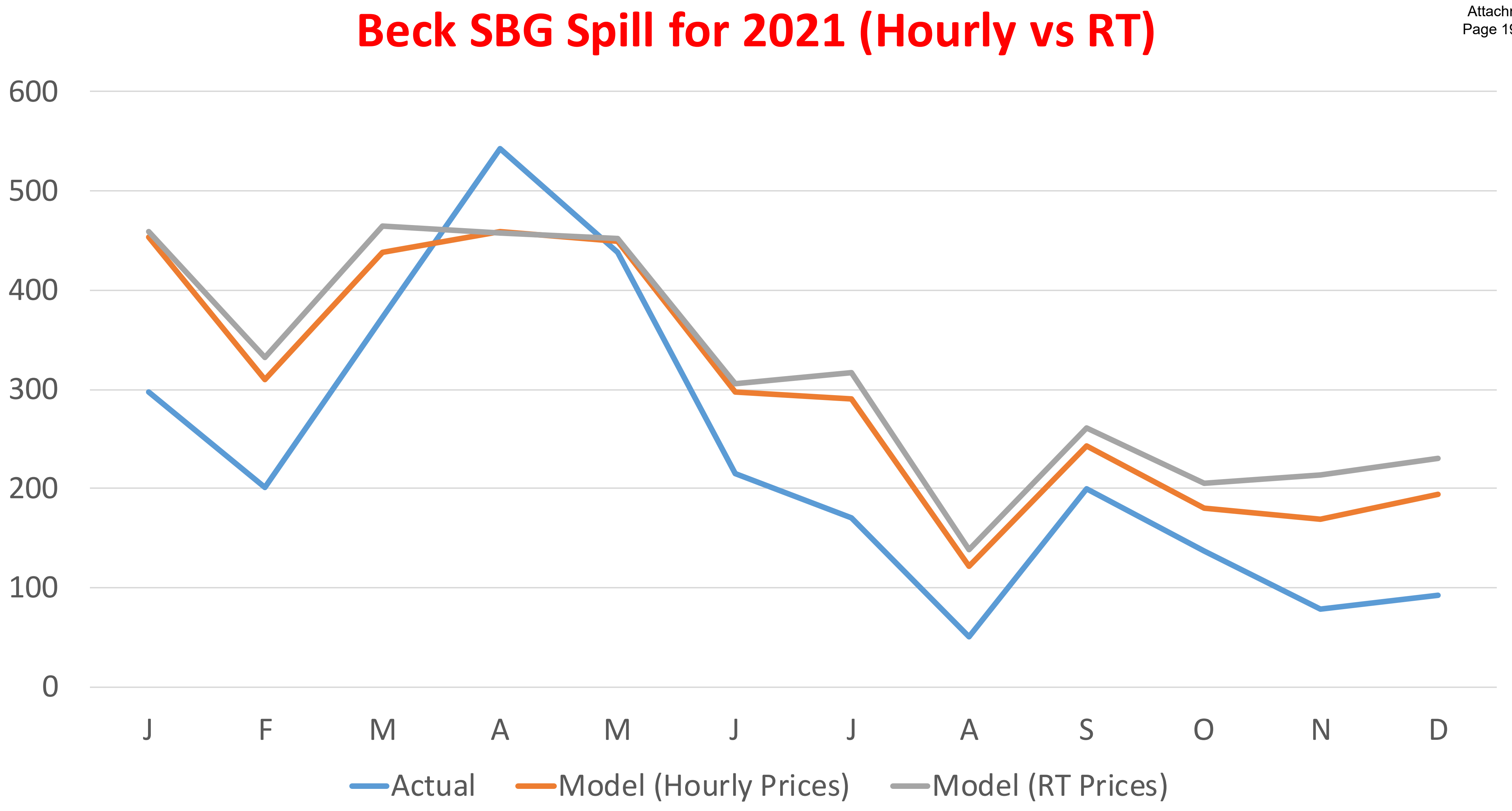


Monthly Madawaska SBG Spill (2021)

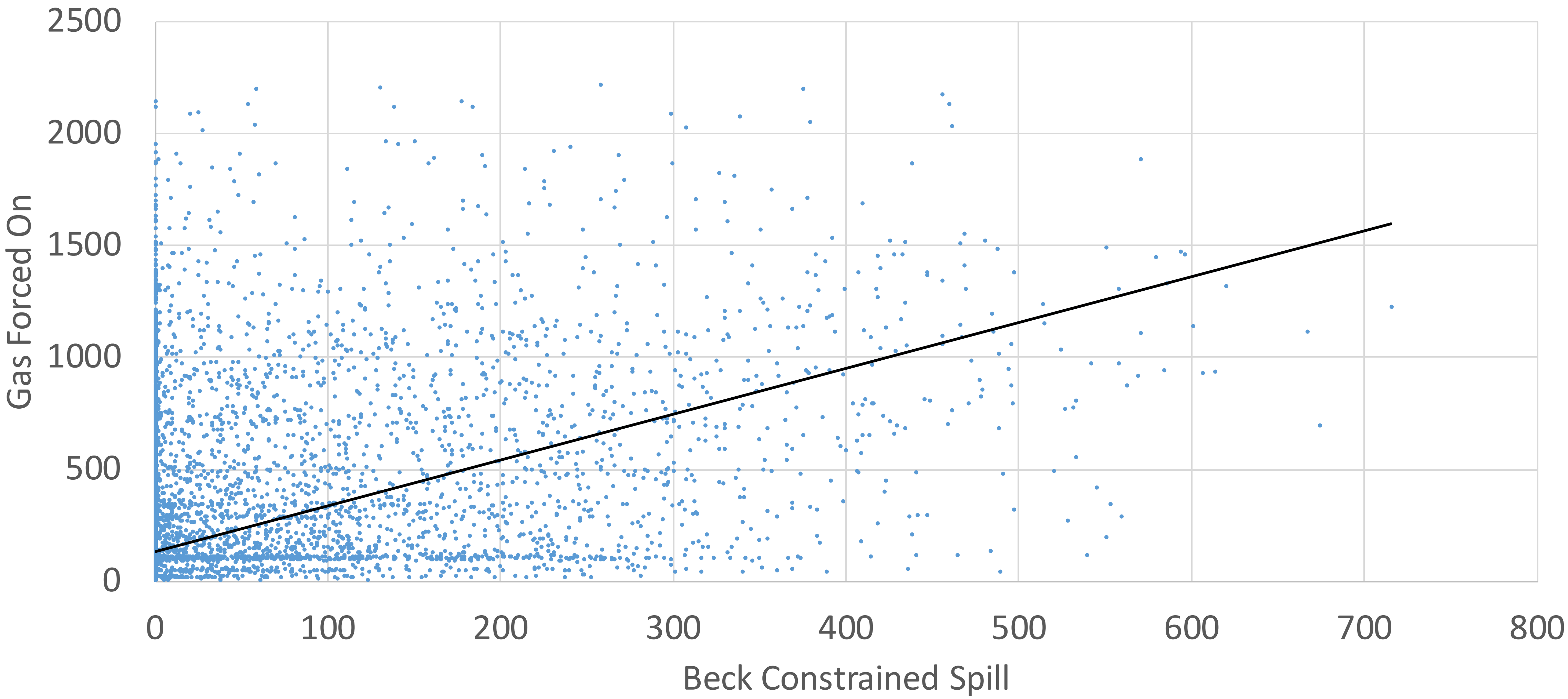


Monthly Beck SBG Spill (2021)




Beck SBG Spill for 2021 (Hourly vs RT)
600
500
400
300
200
100
0
J
F
M
A
M
J
J
A
S
O
N
D
Actual
Model (Hourly Prices)
Model (RT Prices)

Gas Forced On vs. Beck Constrained Spill (2019-2020)



Summary

- Proposed methodology gives reasonably good results for most river systems but performance for Beck is not as good.
- Beck is constrained off for reasons which are not reflected in the marginal congestion cost - for example, CCGT's which are constrained on for OR or for minimum uptime.
- This causes the algorithm to under-estimate constrained-off spill for Beck, which results in an over-estimation of SBG spill.
- Using 5-minute prices instead of hourly prices increases model SBG spill, which actually increases model Beck numbers.

IESO Interrogatory #1

Interrogatory

Reference: Exhibit A1-Tab 2- Schedule 1 Page 1 & Exhibit A2-1-1 Attachment 2

Preamble: Ontario Power Generation (OPG) is requesting an order or orders approving changes to the calculation of amounts for the Hydroelectric Surplus Baseload Generation Variance Account (“SBGVA”) and the Hydroelectric Incentive Mechanism (“HIM”), and approving the treatment of real time make whole payments, resulting from the implementation of the Independent Electricity System Operator’s (“IESO”) Market Renewal Program (“MRP)

OPG states that due to MRP the HIM needs to be revised to reflect new market features including Locational Marginal Prices and settlement of the new day ahead and real-time markets. OPG has proposed a revised HIM to incorporate:

- separate incentives for the day-ahead and real-time timeframe;
- settlement on LMP;
- daily production averaging instead of the current monthly production averaging.

Question:

a) How will OPG’s proposed Day Ahead Market (DAM) HIM incent OPG’s efficient participation in the DAM and result in the optimal scheduling of its regulated hydroelectric resources?
b) How will OPG’s proposed Real-Time (RT) HIM incent its regulated hydroelectric resources to respond to changing RT market conditions?
c) What other possible HIM formulae (DAM & RT) did OPG explore and how did it conclude that this proposal is the best choice?

Response

a) The proposed day-ahead HIM will incent OPG to offer more generation in hours where high day-ahead prices are expected. Since higher prices are associated with hours with higher primary demand, this will result in scheduling day-ahead generation in the hours in which it is most needed, which will reduce the overall system costs.

b) The proposed real-time HIM will incent OPG, once its generation has been scheduled on a day-ahead basis, to use any additional scheduling flexibility to respond to deviations between the real-time and day-ahead markets, which will reduce overall system costs. For example, if prices are expected to increase in the real-time market relative to the day-ahead market then OPG will benefit from shifting generation in the real-time market into these hours accordingly.

c) As OPG's current HIM appropriately incents OPG's hydroelectric facilities to follow market signals, the objective of OPG's revised HIM is to maintain a similar design while incorporating features of the new market.

OPG did not consider any options for the day-ahead incentive other than the one submitted. The IESO has identified the future day-ahead market to be the primary scheduling market. As such, OPG designed an incentive payment which is consistent with the current methodology whereby differences between the day-ahead schedule and the average day-ahead schedule are compensated at the day-ahead price. This provides an incentive for OPG to shift its generation to be scheduled in the highest-priced hours in the day-ahead market to lower system costs.

For the real-time incentive, OPG considered five separate alternatives, which are enumerated in Chart 1 below (where Q_{DA} denotes the day-ahead schedule, P_{DA} denotes the day-ahead price, Q_{RT} denotes the real-time output, P_{RT} denotes the real-time price, $Q_{DIFF} = Q_{RT} – Q_{DA}$, and $P_{DIFF} = P_{RT} – P_{DA}$).

Chart 1

Incentive Code	**Incentive Formula**
RT1	$(Q_{RT} – \text{avg}\ (Q_{RT})) * P_{RT}$
RT2	$(Q_{DIFF} – \text{avg}\ (Q_{DIFF})) * P_{RT}$
RT3	$(Q_{DIFF} – \text{avg}\ (Q_{DIFF})) * P_{DIFF}$
RT4	$Q_{DIFF} * P_{RT}$
RT5	$Q_{DIFF} * P_{DIFF}$

While options RT1 to RT5 were analyzed (see Ex. L-M-SEC-06, Attachment 1), RT2 was ultimately chosen because it most appropriately encourages response to changes between the two markets. This is achieved by compensating responses to changes between the markets at the real-time price whenever the response is greater than the facility's average response to changes. Similarly, whenever the response to changes is less than the average response to changes, the amount payable would be reduced by the response amount at the real-time price. This provides OPG incentive to deviate from its day-ahead schedule based on real-time market signals.

Regarding the design choice of a daily averaging period for measuring performance, refer to Ex. M1-1-1, Section 3.3.4 and Ex. L-M-Staff-13.

IESO Interrogatory #2

Interrogatory

Reference: Exhibit M1, Tab 1, Schedule 1, page 9 of 22 & MRP Energy Stream Business Case page 42

Preamble: in M1-1-1 page 9 OPG states:

"CMSCs are the current market mechanism to recover revenue for forgone production due to local curtailment. In EB-2007-0905, the OEB accepted OPG's proposal to retain CMSC payments as they are designed to compensate for "losses which OPG incurs in constrained on and constrained off situations [which] are mostly related to opportunity costs – the reduced production or less efficient production which results in lost revenues." Without a mechanism to address the elimination of CMSCs under MRP, OPG would necessarily be under compensated for such foregone production under the existing Regulated Framework. Accordingly, OPG is seeking an amendment to the SBGVA to address the impact of spill resulting from local curtailment, as described in the following sub-section."

The OEB's Market Surveillance Panel (MSP) published a report in 2016 titled: "Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform," which discussed problems with the current two-schedule market structure in Ontario, including its concerns with constrained off payments. The IESO has taken many of the MSP concerns into account in the design of MRP, including introducing a single schedule market with locational pricing that makes constraint payments unnecessary.

Question:

a) Why is it appropriate for OPG to continue to be compensated for constrained off generation in the new market?

b) Please provide estimates for the changes in spill quantities and SBGVA additions due to the proposed changes.

Response

a) As explained in Ex. L-M-Staff-20, neither OPG's OEB-approved revenue requirement nor production forecast include a forecast of constrained-off generation. If OPG is not compensated for the revenue lost from foregone generation due to being constrained off, OPG would incur a revenue loss that is unrelated to its operation of the prescribed facilities and instead is due to the operation of the market. This revenue loss would negatively impact OPG's opportunity to earn its authorized rate of return. For these reasons, it is appropriate for OPG’s prescribed facilities to be compensated for foregone generation due to constrained-off events in the new market, as it is in the current market.

b) Refer to Ex. L-M-Staff-23.

IESO Interrogatory #3

Interrogatory

Reference: Exhibit M1, Tab 1, Schedule 1, page 18 of 22

Preamble: Exhibit M1-1-1 page 18 states:

"OPG's assessment of consumer benefits from the HIM concludes that economic time-shifting of its regulated hydroelectric generation reduces modelled consumer costs before OPG incentive payments by an average of $50M per year from 2023 to 2026. This modelled time shifting of production results in a modelled net incentive payment to OPG of $21M per year. The average annual net customer benefit over the modelled period is therefore $29M. The analysis accounts for the market effects of time shifting: the displacement of more expensive generation (i.e., on-peak gas and imports) by hydroelectric production; increases in production and consequent GRC payments for additional on-peak generation at the regulated hydroelectric facilities; reduced payments for SBG-related forgone generation (as determined under OPG's proposal); and changes in exporter payments made to the IESO for off-peak exports that result in changes in customer costs."

Question:

a) Does the customer benefit forecast include changes in SBGVA additions due to the proposed changes in the SBG spill methodology?

Response

a) The customer benefit of HIM is calculated by taking the difference between two scenarios:

   1) A base case where OPG does not shift as much output (i.e., runs in a flatter manner) as it does not have an incentive to time shift; and
   2) A scenario where OPG follows market signals to shift production to the highest price hours.

   In both scenarios, the modelled SBGVA additions include both local and global spill valued at the regulated payment amount less GRC. Thus, the customer benefit calculation assumes the proposed SBG spill methodology is adopted.

SEC Interrogatory #6

Interrogatory

Reference: [M1-1-1, p.11]

Question:

Please provide a copy of any analysis undertaken regarding the potential financial impact of the proposal, as well as any other possible revisions considered to the HIM.

Response

OPG has provided two sets of financial analysis outputs, from the two analyses performed in 2020 and 2021, respectively. Attachment 1 presents the financial analysis performed for the HIM options considered in the initial evaluation, using data for 2017-2019. Attachment 2 provides an updated analysis, including data for 2020, as part of a subsequent evaluation focusing specifically on the proposed HIM design.[1] For convenience, a consolidated summary of the updated analysis is provided in Chart 1 below. Both analyses are based on a comparison of the HIM options using historical market data (referred to as “backtesting”) and as such do not include certain features of the new market.

Chart 1 compares three scenarios:

Scenario 1: Monthly Avg. (Current HIM design)
Scenario 2: Daily Avg. (Current HIM design revised for daily averaging)
Scenario 3: HIM design proposed in this Application

OPG used ‘UB’ to describe the adjustment for unintended benefit and ‘eHIM’ to describe the total of HIM and the adjustment for unintended benefit, which represents the overall financial impact of the HIM proposed in this application.

[1] Values in Attachment 1 and Attachment 2 for the years 2017-2019 differ due to data validation and improvements implemented in the latter analysis.

Chart 1: Summary of Backtest Results

		eHIM Comparison					Inputs Description
		Avg.	2017	2018	2019	2020	
Monthly Avg.	HIM	47.6	58.7	57.0	39.3	35.4	Price: 5 min unconstrained price
(Current)	UB	-34.7	-42.0	-42.0	-28.3	-26.6	Output: 5 min constrained schedule
	eHIM	12.9	16.7	15.1	11.0	8.8	
Daily Avg.	HIM	36.5	48.2	43.4	29.1	25.3	Price: 5 min unconstrained price
(Current Revised)	UB	-20.5	-26.6	-24.2	-15.9	-15.2	Output: 5 min constrained schedule
	eHIM	16.0	21.6	19.2	13.2	10.1	
Proposed eHIM	DA	29.9	30.0	41.5	27.0	21.0	DA Price: DA HE18 Predispatch HOEP
	RT	11.3	16.4	12.3	9.9	6.7	DA Sched: Predisp constrained schedule
	UB	-20.5	-26.6	-24.2	-15.9	-15.2	RT Price: 5-min unconstrained price
	eHIM	20.7	19.8	29.6	21.0	12.5	RT Output: 5-min constrained schedule

Regulated vs. merchant generators

Merchant generators :

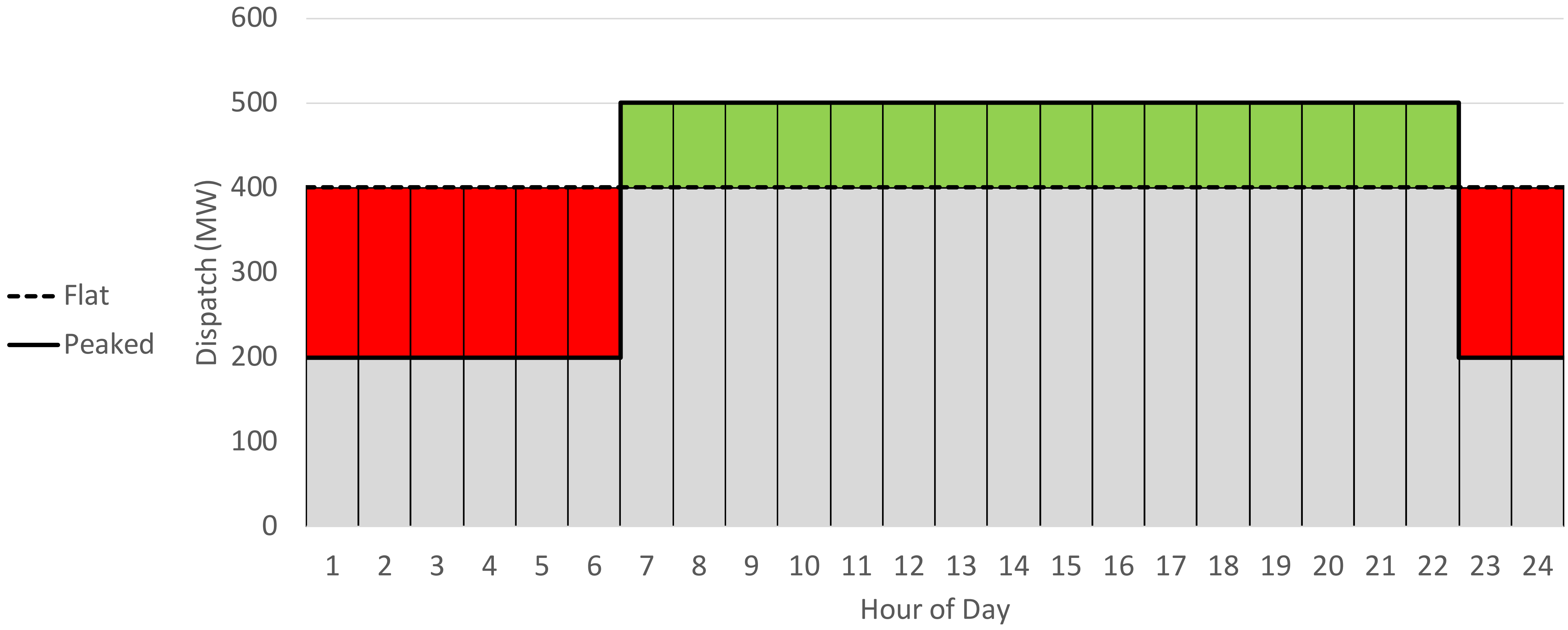
$$\text{Revenue} = \sum \text{Q}_{\text{DA}} \times \text{P}_{\text{DA}} + \sum (\text{Q}_{\text{RT}} - \text{Q}_{\text{DA}}) \times \text{P}_{\text{RT}}$$

Regulated generators :

$$\text{Revenue} = \sum \text{Q}_{\text{RT}} \times \text{P}_{\text{REG}} + (\text{DA incentive}) + (\text{RT incentive})$$

What should DA and RT incentives look like?

DA Incentive



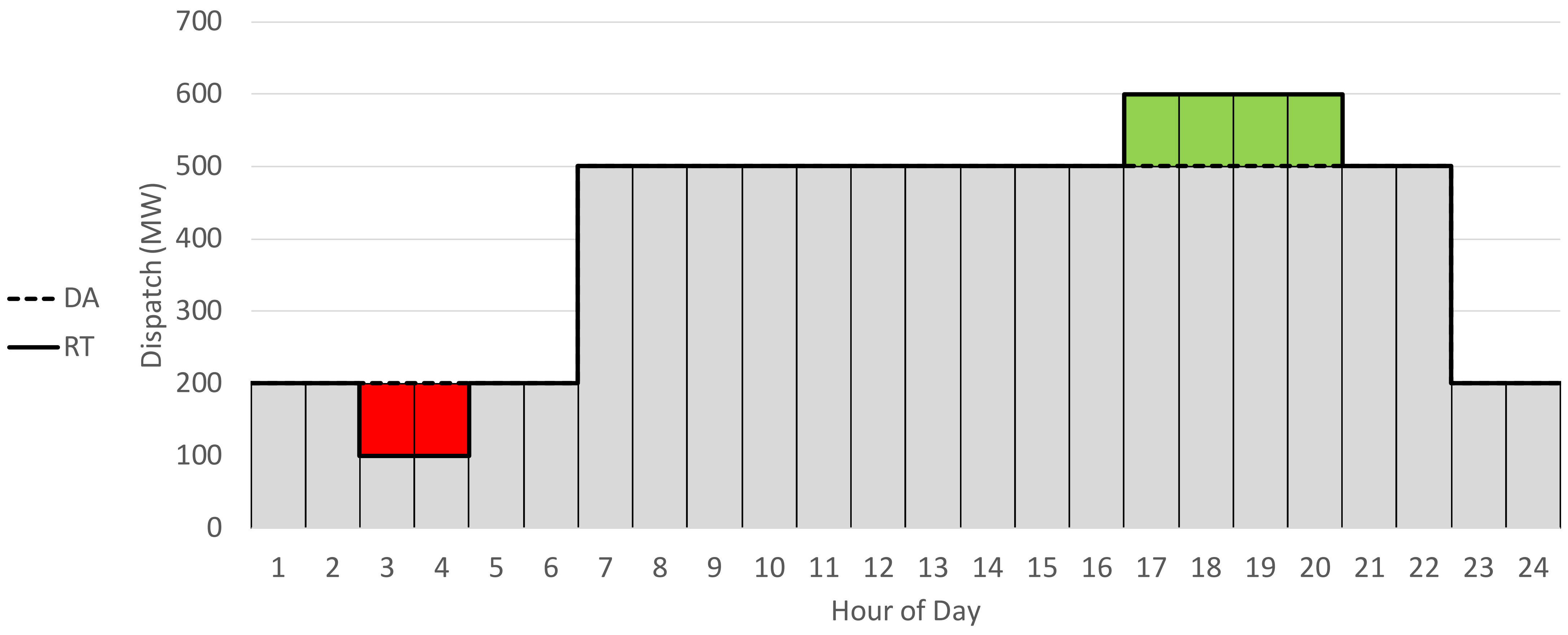
DA Incentive (continued)

- With no incentive we would dispatch in a flat pattern (dashed line).
- With incentive we dispatch with peaked pattern (solid line).
- Value added is sum of green and red regions.

$$\Delta V_{DA} = \sum \left(Q_{DA} - \mathrm{avg}(Q_{DA})\right) \times P_{DA}$$

- Green and red regions must have the same area.
- Assumes that water can only be shifted within the day.
- Could also use weekly or monthly average.

RT Incentive



RT Incentive (continued)

- With no realtime offers we would use DA dispatch schedule.
- Value added is sum of green and red regions.

$$\Delta V_{RT} = \sum (Q_{RT} - Q_{DA}) \times P_{RT}$$

- If only intra-day water shifts are allowed then green area = red area.
- Otherwise, they could have different areas.

Comparison of various incentives

Name	Formula	Comments
DA1	$(Q_{DA} - \overline{Q_{DA}}) \times P_{DA}$	Only possible DA incentive?
RT1	$(Q_{RT} - \overline{Q_{RT}}) \times P_{RT}$	Independent of DA market results
RT2	$(Q_{DIFF} - \overline{Q_{DIFF}}) \times P_{RT}$	Adjusted version of merchant generator payment
RT3	$(Q_{DIFF} - \overline{Q_{DIFF}}) \times P_{DIFF}$	Analog of current HIM formula
RT4	$Q_{DIFF} \times P_{RT}$	Same as merchant generator payment
RT5	$Q_{DIFF} \times P_{DIFF}$	Suggested by Hooshang

$$Q_{DIFF} = Q_{RT} - Q_{DA}$$

$$P_{DIFF} = P_{RT} - P_{DA}$$

$$\overline{Q} = \text{avg}(Q) \qquad \text{(daily, weekly or monthly average)}$$

HIM backtesting - methodology

- Ran separate annual tests for 2017, 2018 and 2019
- Used last DACP pre-dispatch shadow prices as proxy for DA price
- Used realtime shadow prices as proxy for RT price
- Normalized prices into range [-2000, 2000]
- For options with averaging used daily, weekly and monthly averages

HIM backtesting – results (annual MCAD)

		Daily Avg.			Weekly Avg.			Monthly Avg.		
		2017	2018	2019	2017	2018	2019	2017	2018	2019
DA1	$(Q_{DA} - \overline{Q_{DA}}) \times P_{DA}$	38	27	22	36	39	19	30	49	39
RT1	$(Q_{RT} - \overline{Q_{RT}}) \times P_{RT}$	47	27	36	62	32	49	64	30	75
RT2	$(Q_{DIFF} - \overline{Q_{DIFF}}) \times P_{RT}$	33	20	23	43	27	32	55	27	34
RT3	$(Q_{DIFF} - \overline{Q_{DIFF}}) \times P_{DIFF}$	36	16	24	39	27	21	51	40	16
RT4	$Q_{DIFF} \times P_{RT}$	24	48	-2						
RT5	$Q_{DIFF} \times P_{DIFF}$	43	35	5						

		eHIM Comparison					Inputs Description
		Avg.	2017	2018	2019	2020	
Monthly Avg.	HIM	47.6	58.7	57.0	39.3	35.4	Price: 5 min unconstrained price
(Current)	UB	-34.7	-42.0	-42.0	-28.3	-26.6	Output: 5 min constrained schedule
	eHIM	12.9	16.7	15.1	11.0	8.8	
Daily Avg.	HIM	36.5	48.2	43.4	29.1	25.3	Price: 5 min unconstrained price
(Current Revised)	UB	-20.5	-26.6	-24.2	-15.9	-15.2	Output: 5 min constrained schedule
	eHIM	16.0	21.6	19.2	13.2	10.1	
Proposed eHIM	DA	29.9	30.0	41.5	27.0	21.0	DA Price: DA HE18 Predispatch HOEP
	RT	11.3	16.4	12.3	9.9	6.7	DA Sched: Predisp constrained schedule
	UB	-20.5	-26.6	-24.2	-15.9	-15.2	RT Price: 5-min unconstrained price
	eHIM	20.7	19.8	29.6	21.0	12.5	RT Output: 5-min constrained schedule

SEC Interrogatory #7

Interrogatory

Reference: [M1-1-1, p.11]

Question:

Please provide a copy of all analyses undertaken by OPG regarding the efficacy of the current HIM methodology.

Response

The efficacy of the HIM methodology can only be assessed by comparing total system costs when OPG time shifts hydroelectric production under the HIM and an alternate scenario where, absent an incentive, OPG does not time shift to the same extent.

OPG does not have access to the IESO's dispatch algorithm and market inputs; as such, OPG has not performed backward-looking analysis on the efficacy of the current HIM methodology. Instead, OPG performs such analysis, as necessary, on a forward-looking basis. Consistent with this approach, OPG previously provided a total customer cost analysis based on the current HIM methodology in its EB-2013-0321 application[1] as well as for the HIM methodology proposed in this application in Ex. M1-1-1, Section 3.5 (as further detailed in Ex. L-M-SEC-10).

[1] EB-2013-0321, Ex. E1-2-1, section 5.1.

SEC Interrogatory #8

Interrogatory

Reference: [M1]

Question:

For each year between 2010 and 2023, please provide the:

a. Total HIM revenue
b. Total MWh where HIM was a positive amount
c. Total MWh where HIM was a negative amount

Response

Please see Chart 1 below. Note that the HIM calculation necessitates an equal amount of MWh both above and below the monthly average value.

Chart 1: HIM Revenue 2010 – 2023

Year	HIM ($M)	MWh Above	MWh Below
2010	14.3	9,454,267	9,454,267
2011	14.5	9,735,945	9,735,945
2012	15.8	9,243,210	9,243,210
2013	18.1	9,437,199	9,437,199
2014	15.6	10,665,881	10,665,881
2015	26.5	14,936,338	14,936,338
2016	14.0	14,483,452	14,483,452
2017	12.4	15,027,975	15,027,975
2018	10.9	14,683,467	14,683,467
2019	6.2	15,089,306	15,089,306
2020	5.1	14,886,417	14,886,417
2021	16.8	14,255,754	14,255,754
2022	14.3	15,275,886	15,275,886
2023	14.8	15,428,326	15,428,326

SEC Interrogatory #9

Interrogatory

Reference: [M1]

Question:

Please provide a copy of any analysis undertaken by OPG regarding the interaction between the HIM and SBGVA.

Response

OPG previously analyzed the interaction between the HIM and SBGVA as discussed in EB-2013-0321, Ex. E1-2-1, pp. 1-15, and has not undertaken any further analysis since that time. In the EB-2013-0321 Payment Amounts Order, the OEB directed OPG to eliminate the unintended interaction of the HIM due to SBG conditions using the calculation recommended by OEB staff (EB-2013-0321, Ex. L-5.3-1 Staff-061). OPG continues to believe this approach to be a reasonable solution to prevent double payment associated with foregone generation due to SBG conditions through the HIM and SBGVA and believes that the calculation has functioned as intended since implementation. As such, OPG has not undertaken any further analysis of the interaction between HIM and SBGVA and has proposed a similar approach that is underpinned by the principles of the existing design in this Application.

SEC Interrogatory #10

Interrogatory

Reference: [M1-1-1, p.18]

Question:

Please provide a copy of the full modelling analysis OPG undertook.

Response

In Attachment 1, OPG provides the modelling analysis outputs underpinning the HIM customer benefit analysis presented at Ex. M1-1-1, pp. 18-20. A description of the modelling methodology is provided below.

The modelling methodology is similar to that used in OPG's estimation of the HIM customer benefit in EB-2013-0321 (Ex. E1-2-1, Section 5.1), as expanded to incorporate features of the new market under Market Renewal Program and the proposals submitted in this application. OPG uses a proprietary model to conduct its forward-looking total customer cost analysis, which includes:

- An electricity market simulation model that is based on least-cost dispatch using price and quantity offers, including a network model;
- OPG's offer prices and proprietary assumptions for offer strategies of other market participants; and
- Proprietary hourly weather normal profiles of all weather-driven input parameters including electricity demand, wind and solar generation for Ontario and the Northeast interconnect, and detailed modeling of Ontario's hydroelectric system.

The estimated benefit accruing to Ontario customers as a result of the HIM has been forecasted by comparing two scenarios:

1) OPG's offer strategy incented by the HIM to time-shift regulated hydroelectric production in response to market prices; and
2) A base case, where, absent an incentive, OPG does not time shift to the same extent.[1]

[1] This does not mean that the dispatch would represent a flat profile. It was assumed that while minimizing starts and stops, OPG would still offer its units for which there would not be enough inflow to run all day during the highest priced periods.

The two simulations were then compared in terms of the resulting dispatch and total customer cost. The differences resulting from an appropriate incentive arise from:

- Savings on imports;
- Savings on natural gas dispatch;
- Changes in wind dispatch and curtailment;
- Changes in OPG's generation dispatch;
- Reduction in SBGVA amounts; and
- Changes in export revenue.

OPG has provided the modelling output summary tables in Attachment 1:

- The cost section provides the cost changes in millions of dollars between the two scenario runs described above;
- The production section provides the changes in production and prices between the two scenarios, which underlie the cost calculations; and
- The modelled HIM section provides a summary of the forecast HIM payments by year. Note that the SBG values do not take into account efficiencies that are expected by the IESO to reduce spill in the new market.

Cost ($M)	Modelled Output			
Description	**2023**	**2024**	**2025**	**2026**
Imports	12	8	6	13
Non-OPG Gas	**65**	**50**	**39**	**40**
Non-OPG Wind	**(4)**	**(3)**	**(5)**	**(5)**
Total Non-OPG Cost	**73.3**	**55.5**	**38.1**	**48.2**
NewReg Hydro	(22)	(14)	(11)	(11)
Beck + Saunders + DeCew - Pump	(2)	(0)	(3)	(3)
HESA Hydro	(1)	(1)	(1)	(0)
OPG Hydraulic	**(24)**	**(15)**	**(14)**	**(14)**
OPG Gas	**1**	**1**	**3**	**3**
Total OPG Cost	**(23.5)**	**(14.1)**	**(10.6)**	**(11.0)**
Wind SBG	4	3	5	5
OPG Reg Hydro SBG	1	0	2	2
OPG NewReg Hydro SBG	6	6	10	5
Total SBG	**10**	**9**	**18**	**13**
Total Customer Cost	**61**	**47**	**46**	**49**
Export Revenue	(1)	4	(1)	0

Production				
	2023	**2024**	**2025**	**2026**
Imports	0.1	0.1	(0.0)	0.1
Non-OPG Gas	**1.1**	**1.0**	**0.8**	**0.8**
Non-OPG Wind	**(0.0)**	**(0.0)**	**(0.0)**	**(0.0)**
Total Non-OPG Supply	**1.2**	**1.1**	**0.7**	**0.9**
NewReg Hydro	(0.5)	(0.3)	(0.2)	(0.3)
Beck + Saunders + DeCew - Pump	(0.0)	(0.0)	(0.1)	(0.1)
HESA Hydro	(0.0)	(0.0)	(0.0)	(0.0)
OPG Hydraulic	**(0.5)**	**(0.3)**	**(0.3)**	**(0.3)**
OPG Gas	**0.0**	**0.0**	**0.0**	**0.0**
Total OPG Supply	**(0.5)**	**(0.3)**	**(0.3)**	**(0.3)**
Wind SBG	0.03	0.03	0.05	0.04
OPG Reg Hydro SBG	0.04	0.01	0.07	0.08
OPG NewReg Hydro SBG	0.17	0.15	0.28	0.17
Total SBG	**0.24**	**0.19**	**0.41**	**0.30**
HOEP (7x24)	**(1.2)**	**(1.0)**	**(0.7)**	**(0.9)**
HOEP (5x8)	(4.5)	(3.7)	(3.1)	(3.5)
HOEP (5x16)	(0.2)	0.3	0.4	0.4
HOEP (2x24)	(0.1)	(1.0)	(0.6)	(0.9)
Exports (onpk)	(0.0)	(0.0)	(0.0)	(0.0)
Exports (offpk)	0.7	0.8	0.5	0.6
Exports	0.6	0.8	0.5	0.6
Imports (onpk)	0.2	0.2	0.2	0.3
Imports (offpk)	(0.0)	(0.1)	(0.2)	(0.1)
Imports	0.1	0.1	(0.0)	0.1
Annual Net Exports	0.5	0.7	0.5	0.5

Summary

Customer cost Changes in M$ due to time-shifting	2023	2024	2025	2026
Reduced payments to Non-OPG generation	73.3	55.5	38.1	48.2
Reduced payments to OPG generation (negative means increased, excluding eHIM)	-23.5	-14.1	-10.6	-11.0
Reduced of payment to SBG	10.4	9.3	17.8	12.6
Reduced of revenue from export (negative means increased)	-0.8	3.8	-0.7	0.5
Total reduction of customer costs (excluding eHIM)	60.9	46.9	46.1	49.3
additional payments to OPG (due to new HIM mechnism)				
DA HIM	28.9	20.8	24.9	28.2
RT HIM	0.3	0.0	0.1	-0.1
UB	-3.7	-2.8	-5.1	-4.2
Net Benefit (TCC reduction - DA HIM - RT HIM -UB)	35.5	28.9	26.2	25.3

Modelled HIM

		Total
2023	**DA HIM**	28.91
	RT HIM	0.25
	UB	-3.74
	eHIM Total	25.42
	SBG	7.00
2024	**DA HIM**	20.80
	RT HIM	0.02
	UB	-2.82
	eHIM Total	18.00
	SBG	7.36
2025	**DA HIM**	24.93
	RT HIM	0.05
	UB	-5.08
	eHIM Total	19.91
	SBG	15.31
2026	**DA HIM**	28.24
	RT HIM	-0.11
	UB	-4.19
	eHIM Total	23.94
	SBG	9.27

Staff Interrogatory #8

Interrogatory

Ref.: (1) Exhibit M1 / Tab 1 / Schedule 1 / pages 13-15
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 11

Preamble:

The revised HIM formula proposed by OPG incorporates a separate day-ahead and real-time incentive. OPG states in the second reference that the proposed updated HIM calculation "will create the same incentives for efficient use of the company's regulated hydroelectric facilities in the new market."

Question(s):

a) What would be the effect on OPG's incentive to shift production if the revised HIM incorporated a day-ahead incentive only? For example, in OPG's view, would a HIM formula that only incorporated a day-ahead incentive provide a worse, similar or improved incentive for OPG to shift production compared to today?

b) What would be the effect on OPG's incentive to shift production if the revised HIM incorporated a real-time incentive only? For example, in OPG's view, would a HIM formula that only incorporated a real-time incentive provide a worse, similar or improved incentive for OPG to shift production compared to today?

c) If not already addressed in OPG's responses to the questions above, please comment on why it is appropriate for the revised HIM formula to incorporate a separate day-ahead and real-time incentive.

Response

a) If the revised HIM only comprised a day-ahead incentive, OPG would not be incented to respond to real-time market signals. This outcome would be worse than the existing HIM specifically for the real-time market as OPG would not have an incentive to consider and respond to changes that occur between the day-ahead and the real-time markets.

b) If the revised HIM only comprised a real-time incentive, OPG would not be incented to follow market signals in the day-ahead market. This outcome would be worse than the existing HIM, as the new market aims to have the day-ahead market as its primary scheduling market and the real-time as a balancing market for real-time changes.

c) An appropriate incentive mechanism should use relevant market features to utilize available market drivers. The current HIM is designed for the real-time only market. New market features introduced by the Market Renewal Program include a financially binding day-ahead market, which will schedule most supply to meet demand, and a real-time balancing market that will be used to balance deviations between day-ahead and real-time. As such, an appropriate incentive mechanism in the new market should consider both the day-ahead market and the real-time balancing market.

Staff Interrogatory #9

Interrogatory

Ref.: Exhibit M1 / Tab 1 / Schedule 1 / pages 14-15

Preamble:

OPG characterizes the proposed revised HIM formula as “Incentive Payment = DA Incentive + RT Incentive”. OPG states that its proposed real-time incentive “would create an economic driver for OPG to respond to market changes between [day-ahead] and [real-time], while ensuring that OPG only receives an incentive for incremental changes in the [real-time]”.

Question(s):

a) Please briefly explain whether the real-time incentive means that OPG gets paid twice for a quantity scheduled in the day-ahead, or rather, whether the real-time incentive addresses incremental production relative to the day-ahead schedule?

Response

a) OPG’s proposed HIM formula would not result in OPG being paid twice for a quantity scheduled in the day-ahead. The proposal includes two distinct components: a Day Ahead Incentive and a Real Time Incentive. The payment (if any) that OPG receives from the proposed real-time HIM is only based on the difference between the real-time output and the day-ahead schedule. As such, the real-time incentive only addresses incremental changes (i.e., increase or decrease in production) as compared to the day-ahead schedule.

Staff Interrogatory #10

Interrogatory

Ref.: Exhibit M1 / Tab 1 / Schedule 1 / page 14

Preamble:

OPG states that "the IESO expects the new market's DAM to schedule most of the supply, with the intention to provide greater operational certainty to the IESO and greater financial and scheduling certainty to participants".

Question(s):

a) Does incorporating a separate day-ahead and real-time HIM incentive encourage OPG to offer more in one of those two markets compared to if there was no HIM? For example, does the proposed revised HIM formula encourage OPG to offer less of its regulated waterpower into the day-ahead market to potentially benefit from higher market prices in the real-time market? If so, is this appropriate? Why or why not?

b) Has OPG received an opinion from the IESO on the proposed revised HIM in relation to market efficiency, operational needs, consumer interests, any actual or likely perverse incentives brought about by the revision, and any other relevant considerations? If so, please summarize the IESO's opinion. If not, please request an opinion from the IESO and provide it.

Response

a) No. Incorporating a separate day-ahead and real-time HIM incentive would not encourage OPG to offer more in one of the two markets compared to if there was no HIM.

b) OPG requested an opinion from the IESO. The following response was prepared by the IESO:

   An economically efficient electricity market is achieved, in part, when market participants respond to price signals in the wholesale markets. It is important that regulatory constructs do not impair or mute these signals to promote an economically efficient wholesale market.

The IESO has intervened in previous OPG rate applications before the OEB and has supported HIM. From IESO's submission to EB-2013-0321: "Time-shifting hydroelectric production from periods of low market price to periods of high market price benefits consumers by reducing the need to dispatch higher cost supply," and, "The IESO is supportive of providing a strong financial incentive to OPG to time-shift their hydroelectric generation to follow market prices."

Regarding the revised HIM that OPG has proposed for the new market under the Market Renewal Program, the IESO's view is that a mechanism to incent the efficient allocation of energy limited hydroelectric production in the day-ahead and real-time timeframes is important for the well-functioning of the wholesale markets, and OPG's proposed HIM is supportive of this aim.

In the new market, the Day Ahead Market (DAM) is intended to be the primary market that will determine the scheduling of Ontario's non-quick start generation (most of the gas units, biomass, etc.), which generally needs to be scheduled well in advance. When participating in the DAM, the HIM will encourage OPG to offer its flexible hydroelectric resources such that they are scheduled in DAM to enable more optimal scheduling of the non-quick start generators and reduce overall costs to consumers.

In the real-time market, the proposed real-time HIM provides an incentive to OPG to maintain the DAM schedules for its hydroelectric resources if conditions do not differ from the DAM, while also incenting OPG to adjust its offers for these resources when market and system conditions do change from that of the DAM. This behaviour provides needed operational flexibility and leads to more efficient market outcomes.

Staff Interrogatory #11

Interrogatory

Ref.: Exhibit M1 / Tab 1 / Schedule 1 / pages 14-15

Preamble:

OPG proposes the day-ahead incentive to settle based on the day-ahead LMP and the real-time incentive to settle based on the real-time LMP. OPG proposes "that the incentive mechanism settle on a locational/resource basis".

Question(s):

a) Please confirm that by proposing to settle on a "locational/resource basis", OPG means that the LMPs used in the revised HIM calculation would be the LMPs that correspond to each of the individual OPG hydroelectric stations that are subject to the Hydroelectric Incentive Mechanism. Otherwise, please clarify.

b) What would be the effect on OPG's incentive to shift production if the revised HIM was settled on the zonal LMP in the day-ahead and real-time instead of on a locational/resource basis? If there are other relevant considerations, please feel free to comment.

c) Would the amount of incentive payment change depending on whether the calculation of the Hydroelectric Incentive Mechanism was based on the zonal LMP in the day-ahead and real-time instead of on a locational/resource? If so, how? If not, why not?

d) In OPG's view, does a HIM formula that settles on a locational/resource basis provide a worse, similar or improved incentive for OPG to shift production compared to the current practice of settling on the Ontario-wide price?

e) How many "locational/resource basis" LMPs would be involved in the revised LMP calculation for a given hour? Is this the same as the number of OPG hydroelectric stations that are subject to the Hydroelectric Incentive Mechanism? If not, please clarify.

Response

a) OPG confirms that it proposes to use each applicable facility's resource-level LMP for the purposes of calculating the HIM, also at a resource level.

b) OPG's understanding is that the new market will not have zonal prices applicable to dispatchable resources. The new market will have virtual zonal prices applicable to virtual transactions, and an Ontario Zonal Price, which will apply exclusively to non-dispatchable loads for settlement purposes.[1]

c) See response to part b).

d) OPG's incentive to time shift is based on the use of market price signals, which reflect market conditions. These signals are the HOEP in the current market and LMP in the new market. However, OPG is unable to comment on the overall degree and impact of locational drivers on the incentive as compared to the current Ontario-wide price.

e) Each of OPG's hydroelectric stations are metered as one or more resources, with each resource comprising single or multiple generating units, depending on the configuration of each facility. Locational Marginal Prices are available at each of these resources. Based on the current configuration of OPG's 26 applicable regulated hydroelectric stations,[2] there are 58 resources and corresponding LMPs that will receive HIM in the new market.

[1] MRP Market Rule Chapter 7, IESO, March 13, 2024, Section 4.7.2 and 6.6.1. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/imrm/mr-00454-r00-mso-ch7-system-operations-and-physical-markets-20240313.pdf

[2] Some of OPG's embedded regulated hydroelectric facilities do not receive a HIM payment as a result of their connection to the distribution system.

Staff Interrogatory #12

Interrogatory

Ref.: (1) Exhibit M1 / Tab 1 / Schedule 1 / page 14
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 12

Preamble:

At the first reference, OPG's description of the proposed revised HIM formula includes the following expressions:

- LMPDA(*t*): the day-ahead LMP for the resource for each hour, *t*, of the day,
- LMPRT(*t*): the real-time LMP for the resource for each hour, *t*, of the day
- MWRT(*t*): net energy production supplied to the IESO real-time market for each hour, *t*, of the day

At the second reference, the current HIM formula includes the following expression:

- MCP(t): market clearing prices for each hour of the month

Question(s):

a) Please clarify whether the day-ahead and real-time LMPs in the first reference are the simple or weighted averages of the twelve five-minute LMPs in each day-ahead and real-time hour, respectively. If the LMPs are the weighted averages, please clarify what they are weighted by.

b) Please clarify what "net energy production" means in the first reference. For example: net of what?

c) Please clarify whether the "MCP(t)" in the second reference is the simple or weighted average of the twelve five-minute market clearing prices in each hour. If it is the weighted average, please clarify what it is weighted by and whether it is the same as the "Hourly Ontario Energy Price" or "HOEP"?

Response

Consistent with presentation of the HIM equation in previous applications to the OEB, the proposed HIM equation presented on Ex. M1-1-1, p. 14, is expressed using hourly values. Upon implementation, the formula will be adapted to use values corresponding to five-minute intervals as appropriate, consistent with existing settlement practices.

a) The day-ahead and real-time LMPs are neither simple nor weighted averages. The day-ahead LMP used in the proposed HIM equation is an hourly price, consistent with the way it will be published by the IESO. The real-time LMP used in the proposed HIM equation is a five-minute interval price.

b) Net energy production refers to the netting of positive and negative energy meter readings at each applicable resource, including the negative metering readings when the SAB Pump Generating Station is operating in pump mode.

c) The “MCP(t)” in the second reference is the simple average of the twelve five-minute market clearing prices in each hour.

Staff Interrogatory #13

Interrogatory

Reference:
Ref.: Exhibit M1 / Tab 1 / Schedule 1 / page 15

Preamble:

OPG proposes that the calculation of the Hydroelectric Incentive Mechanism be changed from monthly production averaging to daily averaging. OPG states that "the current monthly averaging implies a monthly storage capability, which overestimates the storage capability at the majority of OPG's regulated hydroelectric resources."

Question(s):

a) Please clarify how the current monthly averaging approach overestimates or does not ideally align with the storage capability at the majority of OPG's regulated hydroelectric resources.

b) Please comment on the implications for the effectiveness of the Hydroelectric Incentive Mechanism of having a daily averaging that would be more in line with the storage capability at the majority of OPG's regulated hydroelectric resources.

c) Would the amount of incentive payment change depending on whether the calculation of the Hydroelectric Incentive Mechanism was based on monthly production averaging or daily averaging? If so, how? If not, why not?

Response

a) The monthly averaging approach implies that OPG has greater flexibility to shift water within a monthly period than permitted by the physical constraints on the watersheds. The available storage capacity that can be used to shift water, and therefore electricity production, at any given reservoir is based on natural geography of the site, regulatory restrictions on water levels and flows, as well as the capacity of the generating station to pass water through the turbines. In addition, regulatory requirements such as Water Management Plans established under Section 23.1 of the *Lakes and Rivers Improvement Act*, limit the amount of flexible water available for generation due to the need to balance other societal interests. Natural inflow conditions can also affect how long it takes to fill the available reservoir volume. While there are some variations based on watershed conditions, the limitations described result in a typical OPG regulated hydroelectric reservoir being able to store water for periods of time that are measured in days or sometimes weeks. For example, the median available storage to shift water to meet peak demand during the 2018-2023 period was approximately one day. For these reasons, the daily averaging approach better aligns with the storage capabilities of OPG's regulated hydroelectric resources than the monthly averaging.

b) The daily averaging feature of the proposed HIM would appropriately incent OPG to time-shift production to the highest priced hours in the day and minimize production during the lowest priced hours in a given day. In addition, OPG will continue to have an incremental incentive to move water from a day with a lower price spread between on- and off-peak periods to a day with higher such price spread, subject to the constraints identified in part a) above, as doing so would result in a higher incentive payment.

c) The HIM payment will change when moving from a monthly to a daily average calculation. The direction of the change depends on the interplay between several factors such as the production profile, market clearing prices and the magnitude of SBG spill. A shorter averaging period will result in lower incentive HIM payments. However, this could be offset by lower HIM adjustment for unintended benefit calculated daily compared to monthly if the months experience high variations of SBG spill (e.g., due to high volumes of freshet water) or high market price volatility. Refer to Ex. L-M-SEC-06 for the financial analysis performed for the HIM options considered.

Staff Interrogatory #14

Interrogatory

Ref.: Exhibit M1 / Tab 1 / Schedule 1 / page 15

Preamble:

OPG proposes that the calculation of the Hydroelectric Incentive Mechanism be changed from monthly production averaging to daily averaging. OPG states that "daily averaging better aligns with the IESO's daily scheduling timeframe of resources in the new market" and that "the IESO's scheduling optimization and settlement of the market will be on a daily resolution."

Question(s):

a) Compared to monthly averaging, would daily production averaging provide any practical advantage by better aligning with the resolution of market scheduling optimization and settlement, or would the advantage of moving to daily averaging be more conceptual? If the advantage is practical, please explain.

b) Is the IESO's scheduling optimization and settlement of the market currently done on a daily resolution, or would that be a new feature brought about by the MRP?

Response

a) Daily averaging offers practical advantages including allowing the calculation of HIM performance after each day to improve performance tracking. Daily averaging also allows the HIM to more accurately reflect performance according to actual conditions of the IESO scheduling day rather than being impacted by events within the month (e.g., outages or shoulder periods of freshet).

b) OPG provides this response based on its understanding of the IESO's documents provided for MRP referenced below.

   There are 3 scheduling optimization timeframes in the IESO market: day-ahead, pre-dispatch and real-time. The IESO's current and future day-ahead scheduling optimization is for 24 hours of the dispatch day. The future day-ahead market settlement for its binding schedules (which does not exist today) will be on an hourly basis.[1]

[1] Day-Ahead Market Calculation Engine, IESO, January 2021. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP_DAM_Calculation-Engine_V2.pdf.

The current pre-dispatch timeframe scheduling optimization is done for each hour of the dispatch day independently. The future pre-dispatch optimization is done for all remaining hours of the dispatch day.[2]

The IESO's current real-time scheduling optimization is done for the next 12 5-minute intervals while the future real-time scheduling optimization is done for the next 11 5-minute intervals. The current and future real-time settlement is on a 5-minute basis. Details can be found in the IESO's detailed design documents.[3,4]

[2] Pre-Dispatch Calculation Engine, IESO, January 2021. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP_PD_Calculation-Engine_Chapter_V2.pdf.
[3] Real-Time Calculation Engine, IESO, January 2021. Retrieve at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP_RT-Calculation-Engine_Chapter_V2.pdf.
[4] Market Settlement, IESO, January 2021. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP_Market-Settlement_Chapter_V2_Working_V2.pdf.

Staff Interrogatory #15

Interrogatory

Ref.: (1) Exhibit M1 / Tab 1 / Schedule 1 / pages 16-17

Preamble:

At reference 1, OPG states that “SBG spill is compensated through an entry to the SBGVA”. OPG also states that “while spill may be forecasted in the DA timeframe, the actual spill that occurs in RT may vary for reasons such as changing market conditions between DA and RT impacting production and changes to inflows and forebay storage levels. Accordingly, OPG’s proposed revised unintended benefit calculation is based on the RT LMP.”

At reference (2), OPG proposes that “SBGVA entries would be calculated using the volume of spill remaining after excluding spill amounts incurred by OPG not attributable to the impact of the presence of SBG conditions.”

Question(s):

a) Please confirm that “while spill may be forecasted in the [day-ahead] timeframe”, it will not be scheduled/committed (or offered) in the day-ahead market, unlike energy production, which will scheduled/committed (and offered) in the day-ahead market. Otherwise, please clarify.

b) Is OPG proposing that SBGVA entries would be calculated on the basis of the volume of spill in the real-time market only? If not, please clarify and reconcile with OPG’s proposal to calculate the revised unintended benefit on basis of the real-time LMP only.

c) Please clarify on why it makes sense to have separate HIM incentives in both the day-ahead and real-time markets, but to have a revised unintended benefit calculation based on the real-time market only.

Response

a) Confirmed.

b) Yes.

c) A HIM incentive that incorporates both the day-ahead and real-time market is appropriate to incent following of market signals in both the day-ahead and real-time market. See Ex. L-M-Staff-08 for further details.

The revised unintended benefit calculation is based on the real-time market only because spill is only observed in real-time. Spill is not scheduled/committed in the day-ahead market. Furthermore, it is not practicable to split the hypothetical portion of the spill that would have occurred based on the day-ahead schedule versus what would have occurred incrementally in real-time. Consequently, the unintended benefit can only be calculated based on the real-time quantity of spill.

Staff Interrogatory #16

Interrogatory

Ref.: Exhibit M1 / Tab 1 / Schedule 1 / page 12

Preamble:

OPG states that "In EB-2010-0008, the OEB required that 50% of the forecast amount of HIM proceeds be returned to customers and incorporated this as a reduction of the revenue requirement. OPG was allowed to retain 50% of the HIM revenue with any excess above the retained amount tracked in the Hydroelectric Incentive Mechanism Variance Account and shared equally between OPG and ratepayers". OPG also states that "in EB-2013-0321, the HIM was expanded to include the newly prescribed facilities, using the same formula. The OEB also increased the variance account threshold to reflect the inclusion of the newly regulated facilities, maintaining a 50% revenue requirement offset and a 50% sharing of additional revenues above the threshold."

Question(s):

a) Please confirm that OPG is not proposing any change in this application to the approved 50% revenue requirement reduction/offset and 50% sharing of additional revenues above the approved threshold. Otherwise, please explain.

b) Please confirm the currently approved forecast of HIM revenues for each remaining year of OPG's current rate framework, the applicable revenue requirement reduction/offset, and the applicable sharing threshold.

c) What is OPG's forecast of HIM revenues for each remaining year of OPG's current rate framework assuming that OPG's revised HIM proposals are implemented?

Response

a) Confirmed.

b) While there is no separate OEB-approved forecast of HIM revenues for years 2024 to 2026, the OEB-approved threshold for the Hydroelectric Incentive Mechanism Variance Account currently in effect has been set at $54.5M based on the forecast of HIM revenues reflected in the hydroelectric payment amounts approved in EB-2013-0321. This amount reflects the average of the 2014 annual threshold of $51M and the 2015 threshold of $58M.[1] The applicable revenue requirement offset is therefore $27.25M (50% of the OEB-specified threshold). OPG shares 50% of any HIM revenues above $54.5M.

c) Based on the total customer cost analysis in Ex. M1-1-1, Section 3.5, and assuming OPG's revised HIM proposals are implemented May 1, 2025, OPG forecasts HIM revenues, net of unintended benefit adjustments, to be $16.3M and $23.9M in 2025 and 2026, respectively. The $16.3M in 2025 accounts for forecast HIM revenues under the current design from January to April ($2.8M) and the proposed design from May to December ($13.5M).

[1] EB-2020-0290, Payment Amounts Order, App. E, p. 5.

Staff Interrogatory #17

Interrogatory

Reference:

(1) Exhibit M1 / Tab 1 / Schedule 1 / page 9
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 21

Preamble:

At the first reference, OPG states that "forgone generation due to market constraints, which are presently compensated via CMSCs, are not also booked in the SBGVA".

At the second reference, OPG states that "there may continue to be conditions in the new market where resources are needed to be scheduled or dispatched out-of-merit that would result in lost cost or lost opportunity requiring MWPs."

Question(s):

a) Does OPG propose to book forgone generation that receives MWPs in the SBGVA? If not, what is OPG's proposal to ensure that OPG does not get compensated twice for the same quantity of forgone production due to SBG: once through the SBGDVA and once through MWPs?

Response

OPG does not propose to book forgone generation that receives MWPs in the SBGVA.

Although, prior to operating in the new market, OPG cannot evaluate all market outcomes that will lead to MWPs, OPG does not expect instances when foregone production would be compensated by both MWPs and through the proposed SBGVA methodology. Based on current IESO information, the foundation of the new single schedule market is such that the LMP will reflect the economic offer and associated dispatch of a resource. The IESO also states that MWPs will only apply in infrequent circumstances when the LMP does not reflect dispatch.[1] This would mean, for example, that when the market requires an OPG hydroelectric resource (which is offered at GRC and has no room to store) to be dispatched down and such dispatch

[1] Single Schedule Market High-Level Design, IESO, August 2019, p. 55. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/SSM-High-Level-Design-Aug2019.ashx

results in foregone generation that qualifies as SBG spill under OPG's proposed methodology, the LMP would be below the resource's offered cost and, since the LMP would reflect the dispatch received, it is OPG's understanding that MWPs would not be calculated. Should an unanticipated market outcome give rise to a situation where SBGVA eligible spill also receives a MWP, OPG would apply the MWP as a credit against the SBGVA. OPG anticipates any such instances to be limited and infrequent.

Staff Interrogatory #18

Interrogatory

Reference:

(1) Exhibit M1 / Tab 1 / Schedule 1 / page 9
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 21

Preamble:

In the existing rate framework and market design, OPG is compensated for forgone revenues that result from forgone production due to SBG. Some of the compensation comes from CMSCs, some of it comes from the SBGVA. In the new market design, the CMSC will be eliminated and therefore won't be available as a mechanism to compensate OPG for forgone revenue due to SBG. OPG therefore proposes to use the SBGVA as the mechanism to recover all of its forgone revenue due to SBG in the new market design.

Question(s):

a) Please confirm that the CMSCs that OPG receives in the current market design for forgone production reflect the difference between the market clearing price and OPG's offer in a given interval. Otherwise please clarify.

b) Please confirm that SBGVA entries reflect the difference between OPG's hydroelectric payment amount and the applicable GRC in a given interval. Otherwise, please clarify.

c) Please estimate and compare the dollar amounts that OPG has received through CMSCs versus the SBGVA per unit of forgone production due to SBG over a recent indicative period. Has OPG typically received more or less compensation per unit of forgone production due to SBG from CMSCs compared to the SBGVA?

d) Does OPG expect that recovery of all of its forgone production due to SBG through the SBGVA will increase or lower the compensation that OPG receives per-unit of SBG spill compared to today?

Response

a) Confirmed.

b) Not confirmed. SBGVA entries reflect the difference between OPG's hydroelectric payment amount and the applicable GRC in a given hour.

c) OPG has calculated a compensation rate [$/MWh] based on historical actuals for the years 2020-2023 for forgone production due to constrained-off conditions compensated though CMSCs (row I) and SBG conditions compensated through the SBGVA (row F) in Chart 1 below:

Chart 1

		2018	2019	2020	2021	2022	2023
(A)	Foregone production due to SBG conditions (GWh)	3,220	3,291	4,315	1,882	1,592	984
(B)	Hydroelectric payment amount ($/MWh)	42.05	42.51	43.15	43.88	43.88	43.88
(C)	Revenue from foregone production due to SBG conditions ($M) [AxB/ 1,000]	135.4	139.9	186.2	82.6	69.9	43.2
(D)	GRC related to foregone production due to SBG conditions ($M)	(42.0)	(42.4)	(55.8)	(26.2)	(22.0)	(13.3)
(E)	Net addition to the SBGVA ($M) [C+D]	93.4	97.5	130.4	56.4	47.9	29.9
(F)	SBGVA compensation rate ($/MWh of foregone production due to SBG conditions) [(Ex1,000,000) / (A* 1,000)]	29.0	29.6	30.2	30.0	30.1	30.3
(G)	CMSCs received in hours where foregone production due to local SBG curtailment was incurred ($M)	19.0	13.0	8.8	23.2	96.1	23.2
(H)	Foregone production due to local SBG curtailment (GWh)	1,135	960	1,232	1,297	2,036	1,363
(I)	CMSC compensation rate ($/MWh of foregone production due to local SBG curtailment) [(Gx1,000,000) / (H* 1,000)]	15.8	12.7	6.7	16.8	44.4	16.0

The difference in compensation rates through the SBGVA compared to CMSCs depends on the difference between the hydroelectric payment amount less GRC and the market clearing price ("MCP") less OPG's offer price, for the foregone production. Historically, OPG's compensation rate for forgone production through the SBGVA (Chart 1, Row F) has typically been higher than the rate of compensation for CMSCs (Chart 1, Row I). However, as seen in 2022 when the MCP was high, the CMSC compensation rate was higher than the SBGVA compensation rate.

d) OPG is unable to speculate if the future compensation rate through the SBGVA per unit of all forgone production will increase or decrease compared to the current combination of CMSC and SBGVA compensation rates, as such compensation rates would vary with the future level of OPG's hydroelectric payment amount and the MCP.

Staff Interrogatory #19

Interrogatory

Reference:

Exhibit M1 / Tab 1 / Schedule 1 / pages 20-21

Preamble:

OPG states that "there may continue to be conditions in the new market where resources are needed to be scheduled or dispatched out-of-merit that would result in lost cost or lost opportunity requiring MWPs".

OPG states that "in the DA timeframe, conditions that could trigger out-of-merit scheduling include "constraint violations, co-optimization of energy with operating reserve or the commitment of an NQS [Non-quick start] resource in the reliability pass of the DAM engine." In the real-time timeframe, OPG starts that "MWP can result from special instructions for "constraint violations, multi-interval optimization, co-optimization with operating reserve or emergency control actions."

Question(s):

a) Do the conditions described above sometimes drive out-of-merit order dispatch instructions in today's market design?

b) How are resources compensated in today's market for following out-of-merit order dispatch instructions driven by the conditions described above? Is it through CMSCs?

c) What is the total dollar amount of CSMC payments that OPG's regulated hydroelectric facilities have received over the past three years? Does OPG have an estimate of how much of that total CMSC dollar amount has related to the conditions described above versus congestion and losses?

d) What is OPG's estimate of the dollar amount that it will receive from MWPs for each remaining year of its current rate term?

Response

a) Yes.

b) Such conditions are compensated through CMSCs in today's market.

c) OPG has provided historical CMSC payments received by the regulated hydroelectric facilities for the last three years in Chart 1. Amounts for 2018-2020 have also been included to provide a more comprehensive representation of historical amounts received.

Chart 1

Year	Total CMSC ($M)
2018	29
2019	25
2020	18
2021	36
2022	114
2023	31

OPG does not have an estimate of the historical CMSC amounts related to out-of-merit dispatches, as OPG does not have all of the information required to isolate these events.

d) Make whole payments result from system related events that are outside of OPG's control. As OPG does not have all of the information required to identify these events, it is unable to provide an estimate of the dollar amount it expects to receive as MWPs for each remaining year of its current rate term in the existing or future market.

Staff Interrogatory #20

Interrogatory

Reference:

Exhibit M1 / Tab 1 / Schedule 1 / page 21

Preamble:

OPG states that CSMC payments/make whole payments are not reflected in the existing payment amounts and would serve to compensate OPG for an identified loss resulting from IESO dispatches.

Question(s):

a) Please clarify how CSMC payments/make whole payments are not reflected in the existing payment amounts. For example, is OPG saying that it does not lower the production forecasts that are used to set its rates to account for future foregone production that would result from following constrained-off instructions? For constrained-on situations, is OPG saying that the incremental cost of producing out-of-merit order is not reflected in the costs which underpin its rates?

Response

a) OPG does not have an OEB-approved regulated hydroelectric revenue requirement or production forecast for the current rate period. In EB-2020-0290, as required under s. 6(2)(13)(i) of O. Reg. 53/05, the OEB established OPG's regulated hydroelectric base payment amount to be $43.88/MWh, being the amount previously established effective January 1, 2021 in EB-2020-0210.[1] The EB-2020-0210 regulated hydroelectric base payment amount was in turn established by the OEB pursuant to the price-cap index approved in EB-2016-0152, as applied to the EB-2013-0321 regulated hydroelectric base payment amount.[2] OPG's OEB-approved revenue requirement and production forecast underpinning the regulated hydroelectric base payment amount were therefore last established in EB-2013-0321. In that proceeding, the revenue requirement did not include CMSCs or a projection of incremental costs from constrained-on operations and

[1] EB-2020-2090, Payment Amounts Order, p. 4.
[2] EB-2016-0152, Payment Amounts Order, p. 9.

the production forecast did not include a forecast of future foregone production due to constrained-off instruction.[3]

[3] An adjustment for untypical biases in the EB-2013-0321 production forecast may have included an immaterial impact from historical system constraints. As discussed in evidence in that proceeding, untypical biases included items such as automatic generation control, operating reserve, condense-mode operations, and system constraints (Ex. EB-2013-0321, Ex. E1-1-1, p. 3).

Staff Interrogatory #21

Interrogatory

Reference:

Exhibit M1 / Tab 1 / Schedule 1 / page 21

Preamble:

OPG states that it "is not seeking approval with respect to the treatment of DA MWPs as they will form part of the day-ahead market settlement and have no impact on OPG's actual output."

Question(s):

a) OEB staff seeks clarification on the relationship among DA and RT MWPs and the approvals sought by OPG in this application. Please clarify why OPG is not seeking approval with respect to the treatment of DA MWPs. Will OPG receive MWPs in the day ahead market? Does it propose to retain them? If so, why is OPG not seeking approval with respect to them?

Response

a) OPG is not seeking approval with respect to the treatment of DA MWPs because section 78.1 of the *Ontario Energy Board Act, 1998* specifies that OPG is compensated with respect to the output generated at its regulated facilities, and unlike RT MWPs which relate to output, DA MWPs relate to the day-ahead schedule and not the output of OPG's regulated facilities. As such, OPG does not propose to retain them.

Staff Interrogatory #22

Interrogatory

Reference:

Exhibit H1 / Tab 1 / Schedule 1 / pages 3-73

Preamble:

The reference above details why OPG would have experienced an economic loss for hours when OPG recorded additions to the Hydroelectric Surplus Baseload Generation Variance Account, but did not pump water at the PGS.

Question(s):

a) Please summarize the information provided at the reference above using the table below. Please feel adapt the table as necessary.

Table: summary of information provided at H1-1-1, pages 3-73

		2018	2019	2020	2021	2022
a	# of spill hours					
b	# of non-spill hours					
c	# of hours not pumping when spill					
d	# of hours pumping when spill					
e	# of hours not pumping when spill because of economic loss due to inability to recover pumping costs					
f	# of hours not pumping when spill because of economic loss due to inability to economically generate					

Response

a) OPG has summarized the information provided in Ex. H1-1-1, Attachment 3, pp. 3-73 in Chart 1 below. This reference only contains hours where an entry to the SBGVA was made and the PGS did not pump. Therefore, there are no non-spill hours shown, nor hours where the PGS was pumping during SBG spill. OPG notes that the numbers in Chart 1 reflect the correction to Ex. H1-1-1, Attachment 3 information as discussed in Ex. L-H-SEC-04(a).

Chart 1: Summary of Spill and Pump Data

	2018	2019	2020	2021	2022
# of spill hours	801	458	1,391	947	238
# of non-spill hours	-	-	-	-	-
# of hours not pumping when spill	801	458	1,391	947	238
# of hours pumping when spill	-	-	-	-	-
# of hours not pumping when spill because of economic loss due to inability to recover pumping costs	594	319	1,135	592	197
# of hours not pumping when spill because of economic loss due to inability to economically generate	207	139	256	355	41

Staff Interrogatory #23

Interrogatory

Reference:
Exhibit H1 / Tab 1 / Schedule 1 / pages 8-11

Preamble:

The Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) records the financial impact of foregone production at regulated hydroelectric facilities due to surplus baseload generation (SBG) conditions.

Question(s):

a) How will the quantity and dollar value of SBG that OPG records in the SBGVA change with the advent of LMP in the new market design?

Response

a) The proposed changes to the SBGVA to include local SBG-related spill will increase the types of spill considered under the SBGVA. However, the IESO expects that the market structure under Market Renewal will provide new efficiencies in the market that will result in reduced curtailment and spilling of water.[1] Therefore, OPG is unable to speculate on the changes in quantity and dollar value of foregone production that will be recorded in the SBGVA in the new market.

[1] Market Renewal Program Energy Stream Business Case, IESO, October 22, 2019, p. 36. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf

Staff Interrogatory #25

Interrogatory

Reference:
(1) Exhibit A1 / Tab 2 / Schedule 1 / page 1
(2) Exhibit M1 / Tab 1 / Schedule 1 / page 1

Preamble:

OPG requests approval of methodologies related to the Hydroelectric Surplus Baseload Generation Variance Account spill calculation, Hydroelectric Incentive Mechanism (HIM), and HIM adjustment for spill, as well as approval to continue to retain real-time make whole payments. OPG makes these requests based on expected changes to Ontario's electricity market that will be made under the IESO's Market Renewal Program.

Question(s):

Please clarify whether OPG is proposing a specific implementation date for the changes that it is proposing to the Hydroelectric Surplus Baseload Generation Variance Account spill calculation, Hydroelectric Incentive Mechanism (HIM), and HIM adjustment for spill, as well as approval to continue to retain real-time make whole payments?

Response

OPG is proposing that the approvals sought within this application pertaining to the Hydroelectric Surplus Baseload Generation Variance Account spill calculation, HIM and HIM adjustment for spill, as well as approval to continue to retain real-time make whole payments be implemented on the date of IESO Market Renewal Program implementation. At the time of this response, the IESO has a target date of May 1, 2025.[1]

[1] Nusbaum, S., Discussion with the Implementation Working Group: MRP Go-Live Date Considerations, Market Renewal Implementation Working Group, IESO, March 13, 2024. Retrieved at https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mrpiwg/mrpiwg-20240313-presentation.pdf