UNDERTAKING JT1.1

Undertaking

TO EXPLAIN WHAT PORTION OF THE MARKET IS CONSTITUTED BY OPG'S REGULATED HYDROELECTRIC GENERATORS AND WHAT PORTION IS BY THE UNREGULATED GENERATORS OF OPG.

Response

OPG's regulated hydroelectric segment and unregulated hydroelectric segment represent approximately 17% and 3%, respectively, of installed generating capacity in Ontario as at December 31, 2023 as reported by the Independent Electricity System Operator ("IESO").

UNDERTAKING JT1.2

Undertaking

WITH REFERENCE TO SEC-02(D) ATTACHMENT 3, NO. 8, TO PROVIDE A COST BREAKDOWN SPECIFIC TO THE WINDING ISSUE, INCLUDING SCHEDULE DELAY, AND WHETHER OPG WAS SUCCESSFUL IN ANY LIQUIDATED DAMAGE RECOVERY.

Response

OPG understands that the undertaking is intended to refer to Ex. L-H-SEC-01, Attachment 3, item no. 8.

OPG has obtained liquidated damages in the amount of [redacted] for the windings issue and associated delay to the Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade project. This payment was applied to reduce the total project cost and is therefore already accounted for in the amounts OPG seeks to recover through the Capacity Refurbishment Variance Account in this proceeding.

UNDERTAKING JT1.3

Undertaking

WITH REFERENCE TO ATTACHMENT 6, TO ADVISE WHETHER OR NOT THEY WERE SUCCESSFUL IN ACHIEVING LIQUIDATED DAMAGES DUE TO POOR CONTRACTOR SCHEDULED PERFORMANCE, AND CONFIRM THAT IT HAS BEEN CONSIDERED IN THE COST THAT OPG IS TAKING TO RECOVER.

Response

In reference to Ex. L-H-SEC-01, Attachment 6, OPG pursued liquidated damages and will receive compensation with respect to the Manitou Falls GS – Auto Sluice System Replacement project ("Manitou Falls project"). The contractor will compensate OPG, [redacted], no later than [redacted]. The compensation, [redacted], will be applied against future regulated hydroelectric work as the Manitou Falls project will have been completed.

UNDERTAKING JT1.4

Undertaking

ON A BEST-EFFORTS BASIS, WITH RESPECT TO THE ENTRIES IN THE CAPACITY REFURBISHMENT VARIANCE ACCOUNT, TO ADVISE THE TOTAL COVID COST BY YEAR FOR THESE PROJECTS, BROKEN OUT INTO CAPITAL AND NON-CAPITAL; TO PROVIDE A BEST-EFFORTS DISCUSSION OF THE SCHEDULE DELAY IMPACT ON INTEREST COSTS AS PART OF THE PROJECTS THAT ARE LAID OUT IN THIS EVIDENCE, AS WELL AS WHERE THERE IS REFERENCE TO ADDITIONAL OPG MANAGEMENT COSTS IN THE CONTEXT OF THOSE SCHEDULED DELAYS.

Response

Set out below are the regulated hydroelectric projects for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding that OPG estimates incurred direct costs as a result of the COVID-19 pandemic (e.g., costs associated with additional cleaning, quarantine and supplies) over the period. A summary of these costs, by year, is provided in Chart 1. All of these costs are capital in nature. Cost impacts resulting from the schedule extensions due to the COVID-19 pandemic are included in the overall schedule impacts provided in the latter part of this response and are not separately available.

Chart 1: Estimated COVID-19 Direct Costs

Project ($M)	2020	2021	Total
Sir Adam Beck I Generating Station – Unit G5 Major Overhaul	0.5	0.1	0.6
Whitedog Falls Generating Station – Sluicegate #1, #4, #5, #6 Replacement	0.2	0.1	0.3
Aguasabon Generating Station – Surge Tank Replacement	-	0.9	0.9
Abitibi Canyon Generating Station – Unit G5 Stator Winding Replacement	0.1	-	0.1
Caribou Falls Generating Station – Sluicegate #4 and #6 Replacement	-	0.1	0.1
Sir Adam Beck I Generating Station – Units G1, G2 Replacement	0.4	0.5	0.9
Ranney Falls Generating Station G3	0.0	-	0.0

R.H. Saunders Generating Station – Replacement of Westinghouse Excitation	0.0	-	0.0
Total	**1.2**	**1.7**	**2.9**

Numbers may not add due to rounding

Set out below are the regulated hydroelectric projects for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding that OPG estimates incurred costs in excess of the First Execution BCS estimate as a result of schedule delays over the period. A summary of these costs is provided in Chart 2. All of these costs are capital in nature. Cost impacts resulting from the schedule delays due to the COVID-19 pandemic are included in these impacts.

Chart 2: Estimated Interest and Project Management Costs Due to Schedule Extension

Project ($M)	Interest Costs	Project Management Costs
Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade	0.8	0.1
Stewartville Generating Station – Sluicegate Replacement	0.0	0.0
Manitou Falls Generating Station – Auto Sluice System Replacement	0.1	0.1
Sir Adam Beck I Generating Station – Unit G5 Major Overhaul	0.7	0.1
Pine Portage Generating Station – Auto Sluice System Replacement	0.1	0.2
Caribou Falls Generating Station – Auto Sluice System	0.1	0.1
Total	**1.8**	**0.6**

Numbers may not add due to rounding

As noted in Ex. JT1.2, for the Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade project, OPG recovered liquidated damages in the amount of [redacted] for the windings issues and associated schedule delays, which was applied to reduce the total project cost and therefore the amounts OPG seeks to recover through the Capacity Refurbishment Variance Account in this proceeding. As the payment was not specifically allocated, the benefit of the liquidated damages is not included in Chart 2.

UNDERTAKING JT1.5

Undertaking

TO PROVIDE COMMENT ON INSTANCES WHERE A PIR WAS REQUIRED.

Response

Under OPG's current governance, a post-implementation review ("PIR") is required for Level A and Level B projects[1], and strategic projects or programs. Of the regulated hydroelectric projects completed under this governance for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding, only the Ranney Falls Generating Station G3 project, the Sir Adam Beck I Generating Station – Units G1, G2 Replacement project, and the Sir Adam Beck I Generating Station – Unit G5 Major Overhaul project meet these criteria. Additionally, under the current governance, a PIR can be required at the discretion of the project sponsor or line approver. Under OPG's previous governance, a requirement for a comprehensive PIRs (equivalent to the current PIRs) was established at the discretion of the project sponsor or line approver.

[1] Project level (Level A to Level D) is a function of the life cycle cost and overall complexity of the project. Further details on this internal classification under OPG's project management governance can be found at EB-2020-0290 Ex. L-D2-01-AMPCO-034, Attachment 1, p. 23.

UNDERTAKING JT1.6

Undertaking

TO FILE THE REFERENCED DOCUMENT, IF IT BECOMES AVAILABLE; IF NOT AVAILABLE, TO CONFIRM THE DATES IN IT, IF KNOWN.

Response

The document referenced in this undertaking, which is the Post-Implementation Review ("PIR") for the Sir Adam Beck I Generating Station – Unit G5 Major Overhaul Project, is scheduled to be completed in October 2024.

UNDERTAKING JT1.7

Undertaking

TO CONFIRM HOW MUCH OF INTERNAL OPG COSTS RELATE TO INTERNAL LABOUR COSTS.

Response

Of the $22.3M of internal OPG costs incurred over 2020-2022 in connection with non-capital preliminary planning and preparation activities for a Darlington SMR as referenced in Ex. L-H-Staff-05, part a), $19.8M relates to internal OPG labour costs.

Chart 1

Cost Category	($M)			
	2020	2021	2022	Total
Licensing	2.3	3.5	0.0	5.8
OPG Project Management and Engineering Oversight	2.8	11.0	0.1	13.9
OPG Site Specific and Other Activities	0.0	0.0	0.2	0.2
Total	**5.1**	**14.5**	**0.3**	**19.8**

Numbers may not add due to rounding

UNDERTAKING JT1.8

Undertaking

TO ADVISE THE DIFFERENCE BETWEEN THE P50 IN THE STUDY ON COMPENSATION COSTS, COMPARED TO THE ACTUAL INTERNAL OPG LABOUR COSTS THAT ARE SOUGHT FOR RECOVERY IN THIS VARIANCE ACCOUNT, ON A BEST-EFFORTS BASIS; TO INCLUDE CALCULATIONS OR ASSUMPTIONS USED.

Response

Below OPG provides a response prepared by Towers Watson ("WTW") with respect to OPG labour costs over 2020-2022 recorded as part of the Nuclear Development Variance Account balances sought for disposition in this Application, as set out at Ex. H1-1-1, Table 20 and further detailed in Ex. L-H-Staff-05 and Ex. JT1.7.

The following response has been prepared by WTW:

Charts 1 and 1.1 below provide an estimate of the dollar difference, by year, between total remuneration, excluding and including Hydro One shares, respectively, for each of PWU, Society and Management employee groups and the market 50th percentile ("P50")[1] for these groups for the OPG labour amounts recorded in the Nuclear Development Variance Account.[2]

Chart 1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (excluding Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Management ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]		$2	[redacted]		$215	[redacted]		($369)	[redacted]		($151)
2021			$6			$954			($804)			$156
2022			$0			$0			($15)			($14)

Note: differences in the variance column are due to rounding.

[1] Market 50th percentile (P50) as determined in the 2019 Total Compensation Benchmarking Study filed at EB-2020-0290, Ex. F4-3-2, Attachment 2.
[2] Temporary employees and Society-represented Extended Temporary Employees were not included in the 2019 Total Compensation Benchmarking Study.

Chart 1.1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (including Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Management ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]		$2	[redacted]		$234	[redacted]		($369)	[redacted]		($132)
2021			$6			$1,034			($804)			$237
2022			$0			$0			($15)			($14)

Note: differences in the variance column are due to rounding.

To respond to this undertaking, WTW used a consistent methodology and assumptions as set out in EB-2020-0290, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18. Namely, for each applicable year, the market values and OPG information reflected in the results of WTW's 2019 compensation benchmarking report provided in EB-2020-0290 were adjusted, and corresponding dollar differences calculated, based on the following steps and assumptions:

- Update the OPG benchmark data based on changes in salary assumed in OPG's applicable business plan underpinning the EB-2020-0290 application, as provided in Chart 2 below;
- Adjust the market benchmark data based on future wage/salary increases determined by WTW, as provided in Chart 2 below; and
- Proportionately adjust the resulting dollar differences to reflect the number of full-time equivalent employees within PWU, Society and Management groups underpinning the OPG labour amounts recorded in the Nuclear Development Variance Account, as provided by OPG. Chart 3 below provides the number of such PWU, Society and Management full-time equivalent employees.

OPG salary and market salary movement assumptions from 2019 to the applicable years are the ones used in the previous analysis provided in EB-2020-2090, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18.

Chart 2: Salary Increase Assumptions for OPG and the Market

[redacted]

Chart 3: Number of Full-time Equivalent Employees for the Identified Projects

Representation	OPG Headcount (FTE)		
	2020	2021	2022
PWU - Regular	0.1	0.3	0.0
PWU - Term	0.0	0.0	0.0
Total PWU	**0.1**	**0.3**	**0.0**
Society - Regular	10.3	42.7	0.1
Management	12.5	26.1	0.8
Total	**22.9**	**69.1**	**0.9**

Consistent with EB-2020-0290, WTW notes that in the total remuneration calculation, total direct compensation reflects the cost of the employer providing the target level of compensation, while pension and benefits values represent the estimated employer provided value. The pension and benefit values may not align directly with the cost for OPG to provide these programs; therefore, WTW suggests caution in using total remuneration, which reflects a mix of cost and value, to assess OPG's overall cost competitiveness relative to the market 50th percentile.

UNDERTAKING JT1.9

Undertaking

WITH REFERENCE TO H-1-1-1, TABLE 15, THE NUCLEAR CAPACITY REFURBISHMENT VARIANCE ACCOUNT, TO CONFIRM HOW MUCH OF THE COSTS ARE INTERNAL OPG LABOUR; TO CONFIRM THE DIFFERENCE BETWEEN THE P50 IN THE COMPENSATION STUDY PROVIDED IN THE 290 PROCEEDING AND THOSE INTERNAL LABOUR COSTS.

Response

Below OPG provides a response prepared by Towers Watson ("WTW") with respect to non-capital OPG labour costs for the nuclear projects and initiatives recorded as part of the Capacity Refurbishment Variance Account balances sought for disposition in this Application, as set out at Ex. H1-1-1, Table 15, except Pickering Extended Operations.[1] As explained at Ex. H1-1-1, p. 20, the Pickering Extended Operations initiative was completed within the total cost budget approved in EB-2016-0152. The labour costs within this total cost forecast formed part of the total compensation costs sought as part of that application, and as approved by the OEB with applicable adjustments including consideration of OPG's Total Compensation Benchmarking Study results filed in that proceeding.[2] As such, OPG has not performed further analysis on the Pickering Extended Operations amounts as part of this undertaking response.

The following response has been prepared by WTW:

Charts 1 and 1.1 1 below provide an estimate of the dollar difference, by year, between total remuneration, excluding and including Hydro One shares, respectively, for each of PWU, Society and Management employee groups and the market 50th percentile ("P50")[3] for these groups for the non-capital OPG labour amounts recorded in the Capacity Refurbishment Variance Account for the following projects and initiatives identified at Ex. H1-1-1, Table 15: Fuel Channel Life Extension ("FCLE") Project, FCLE Related Ongoing Costs, Darlington Annulus Spacer Life Management Project, and Darlington U3 Fuel Channel Component Retrieval Project.[4]

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[1] There were no non-capital OPG labour costs incurred for the Darlington Steam Generator Primary Moisture Separator Replacement project.
[2] EB-2016-0152, Decision and Order, section 5.9.
[3] Market 50th percentile (P50) as determined in the 2019 Total Compensation Benchmarking Study filed at EB-2020-0290, Ex. F4-3-2, Attachment 2.
[4] Temporary employees and Society-represented Extended Temporary Employees were not included in the 2019 Total Compensation Benchmarking Study.

Chart 1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (excluding Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Management ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]		$5	[redacted]		$235	[redacted]		($34)	[redacted]		$206
2021			($65)			$155			($17)			$73
2022			($47)			$101			($43)			$11

Note: differences in the variance column are due to rounding.

Chart 1.1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (including Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Management ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]		$24	[redacted]		$256	[redacted]		($34)	[redacted]		$246
2021			($55)			$168			($17)			$96
2022			($36)			$110			($43)			$32

Note: differences in the variance column are due to rounding.

To respond to this undertaking, WTW used a consistent methodology and assumptions as set out in EB-2020-0290, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18. Namely, for each applicable year, the market values and OPG information reflected in the results of WTW's 2019 compensation benchmarking report provided in EB-2020-0290 were adjusted, and corresponding dollar differences calculated, based on the following steps and assumptions:

- Update the OPG benchmark data based on changes in salary assumed in OPG's applicable business plan underpinning the EB-2020-0290 application, as provided in Chart 2 below;
- Adjust the market benchmark data based on future wage/salary increases determined by WTW, as provided in Chart 2 below; and
- Proportionately adjust the resulting dollar differences to reflect the number of full-time equivalent employees within PWU, Society and Management groups underpinning the non-capital OPG labour amounts recorded in the Capacity Refurbishment Variance Account for the projects listed above, as provided by OPG. Chart 3 below provides the number of such PWU, Society and Management full-time equivalent employees.

OPG salary and market salary movement assumptions from 2019 to the applicable years are the ones used in the previous analysis in EB-2020-2090, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18.

Chart 2: Salary Increase Assumptions for OPG and the Market

Chart 3: Number of Full-time Equivalent Employees for the Identified Projects

Representation	OPG Headcount (FTE)														
	FCLE Project			FCLE Related Ongoing Costs			Darlington Annulus Spacer Project			Darlington U3 Project			TOTAL		
	2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022
PWU - Regular	0.0	0.0	0.0	7.2	3.2	1.2	0.0	0.0	0.0	0.0	0.1	0.7	7.3	3.4	1.9
PWU - Term	0.0	0.0	0.0	2.6	2.5	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.5	2.0
Total PWU	**0.0**	**0.0**	**0.0**	**9.9**	**5.7**	**3.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.7**	**9.9**	**5.8**	**3.8**
Society - Regular	1.5	1.3	1.0	7.8	4.4	0.9	1.9	1.2	1.2	0.1	0.1	0.2	11.3	6.9	3.2
Management	0.7	0.3	0.1	0.4	0.0	0.2	0.0	0.3	0.3	0.0	0.0	0.0	1.2	0.5	0.5
Total	**2.2**	**1.6**	**1.0**	**18.1**	**10.0**	**4.2**	**1.9**	**1.5**	**1.5**	**0.1**	**0.2**	**0.9**	**22.4**	**13.3**	**7.6**

Note: differences in the total row are due to rounding.

Consistent with EB-2020-0290, WTW notes that in the total remuneration calculation, total direct compensation reflects the cost of the employer providing the target level of compensation, while pension and benefits values represent the estimated employer provided value. The pension and benefit values may not align directly with the cost for OPG to provide these programs; therefore, WTW suggests caution in using total remuneration, which reflects a mix of cost and value, to assess OPG's overall cost competitiveness relative to the market P50.

UNDERTAKING JT1.10

Undertaking

WITH REFERENCE TO H-1-1-1, TABLE 7, NON-CAPITAL COSTS, TO CONFIRM HOW MUCH IS OPG LABOUR COSTS; TO COMPARE BETWEEN THE P50 IN THE COMPENSATION STUDY IN THE 290 PROCEEDING, AND THE INTERNAL LABOUR COST FOR WHICH RECOVERY IS SOUGHT IN THIS PROCEEDING.

Response

Below OPG provides a response prepared by Towers Watson ("WTW") with respect to non-capital OPG labour costs for regulated hydroelectric projects recorded as part of the Capacity Refurbishment Variance Account balances sought for disposition in this Application, as set out at Ex. H1-1-1, Tables 7 and 7a.[1] The information is provided for 2020 only as that is the sole year in which non-capital OPG labour costs were captured as part of the above Capacity Refurbishment Variance Account balances.

The following response has been prepared by WTW:

Charts 1 and 1.1 below provide an estimate of the dollar difference, by year, between total remuneration, excluding and including Hydro One shares, respectively, for each of PWU, Society and Management employee groups and the market 50th percentile ("P50")[2] for these groups for the non-capital OPG labour amounts recorded in the Capacity Refurbishment Variance Account for the following projects identified at Ex. H1-1-1, Table 7a: Abitibi Canyon Generating Station – Unit G5 Stator Winding Replacement and Sir Adam Beck I Generating Station – Unit G5 Major Overhaul.[3]

Chart 1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (excluding Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]		$38	[redacted]		$0	[redacted]		$39

[1] OPG labour costs were incurred for the Abitibi Canyon Generating Station – Unit G5 Stator Winding Replacement and Sir Adam Beck I Generating Station – Unit G5 Major Overhaul projects only.
[2] Market 50th percentile (P50) as determined in the 2019 Total Compensation Benchmarking Study filed at EB-2020-0290, Ex. F4-3-2, Attachment 2.
[3] Temporary employees and Society-represented Extended Temporary Employees were not included in the 2019 Total Compensation Benchmarking Study.

Chart 1.1: Estimated Dollar Difference between Total Remuneration – OPG and Market P50 (including Hydro One shares)

	PWU ($Thousands)			Society ($Thousands)			Overall ($Thousands)		
	OPG	Market	$ Variance	OPG	Market	$ Variance	OPG	Market	$ Variance
2020	[redacted]	[redacted]	$43	[redacted]	[redacted]	$0	[redacted]	[redacted]	$43

Note: differences in the variance column are due to rounding.

To respond to this undertaking, WTW used a consistent methodology and assumptions as set out in EB-2020-0290, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18. Namely, for each applicable year, the market values and OPG information reflected in the results of WTW's 2019 compensation benchmarking report provided in EB-2020-0290 were adjusted, and corresponding dollar differences calculated, based on the following steps and assumptions:

- Update the OPG benchmark data based on changes in salary assumed in OPG's applicable business plan underpinning the EB-2020-0290 application, as provided in Chart 2 below;
- Adjust the market benchmark data based on future wage/salary increases determined by WTW, as provided in Chart 2 below; and
- Proportionately adjust the resulting dollar differences to reflect the number of full-time equivalent employees within PWU, Society and Management groups underpinning the non-capital OPG labour amounts recorded in the Capacity Refurbishment Variance Account for the projects listed above, as provided by OPG. Chart 3 below provides the number of such PWU, Society and Management full-time equivalent employees.

OPG salary and market salary movement assumptions from 2019 to the applicable years are the ones used in the previous analysis provided in EB-2020-2090, Ex. L-F4-03-SEC-149 and EB-2020-0290, Ex. JTX4.18.

Chart 2: Salary Increase Assumptions for OPG and the Market

Chart 3: Number of Full-time Equivalent Employees for the Identified Projects

Representation	OPG Headcount (FTE)		
	Abitibi - Unit G5	SAB - Unit G5	TOTAL
PWU - Regular	1.2	0.7	1.9
PWU - Term	0.0	0.0	0.0
Total PWU	**1.2**	**0.7**	**1.9**
Society - Regular	0.0	0.0	0.0
Total	**1.2**	**0.7**	**1.9**

Note: differences in the total row are due to rounding.

Consistent with EB-2020-0290, WTW notes that in the total remuneration calculation, total direct compensation reflects the cost of the employer providing the target level of compensation, while pension and benefits values represent the estimated employer provided value. The pension and benefit values may not align directly with the cost for OPG to provide these programs; therefore, WTW suggests caution in using total remuneration, which reflects a mix of cost and value, to assess OPG's overall cost competitiveness relative to the market P50.

UNDERTAKING JT1.11

Undertaking

TO CONFIRM WHETHER PROJECTS OPG SEEKS RECOVERY FOR THROUGH THE CRVA FOR PRE-JUNE 1, 2017, INCREASED OPERATING CAPACITY.

Response

OPG confirms that none of the regulated hydroelectric projects placed into service before June 1, 2017[1] for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding resulted in increased station generating capacity.

[1] As referenced in Ex. H1-1-1, p. 16, lines 6-15.

UNDERTAKING JT1.12

Undertaking

IF THE RESPONSE TO THE PREVIOUS UNDERTAKING QUESTION IS SUCH THAT THERE WERE INCREASES IN CAPACITY RESULTING FROM ANY OF THOSE PROJECTS, TO INDICATE WHEN THAT INCREMENTAL CAPACITY CAME ONLINE.

Response

For the regulated hydroelectric projects outlined in Ex. L-H-SEC-01, Chart 5, which have actual in-service additions between June 1, 2017 and December 31, 2021 and resulted in increased hydroelectric generating capacity, Chart 1 below sets out the dates when such incremental capacity came online.

Chart 1

Project	Maximum Continuous Rating (MCR) Increase (MW)	Date Synchronized to Grid
Sir Adam Beck I GS – Unit G10 Major Overhaul and Upgrade	45.9 to 55.0	June 9, 2017
Sir Adam Beck I GS – Unit G5 Major Overhaul	53.1 to 58.0	September 21, 2021
Sir Adam Beck I GS – Units G1, G2 Replacement	0 to 57.5 per unit	G1: October 26, 2022 G2: May 19, 2022
Ranney Falls GS G3	0.8 to 10	June 27, 2022

Refer to Ex. JT1.11 for discussion of projects with in-service additions before June 1, 2017.

UNDERTAKING JT1.13

Undertaking

WITH REFERENCE TO SEC-04, PART B, TO CONFIRM WHETHER THE ESTIMATED LOSSES IF THE PUMP WAS OPERATIONAL ARE SIMILAR TO COLUMN XII IN THE ATTACHMENT, FORECASTE REVENUE IN THE NEXT ON-PEAK PERIOD; TO ADVISE HOW DECISIONS ON UTILIZATION WOULD BE AUDITED.

Response

OPG understands the undertaking is asking, with reference to Ex. L-H-SEC-04, Attachment 1, whether the forecasted revenue in the next on-peak period provided in column VII ("Forecast revenues in next on-peak period (before GRC costs)") is calculated similarly to the estimated losses provided in column XII ("Estimated loss if pump was operated") by using pre-dispatch prices rather than forecast prices used by operators to make decisions regarding PGS utilization, and to advise how OPG's decision-making on PGS utilization could be verified (Tr. Tech. Conf., April 4, 2024, p. 77, lines 27-28, p. 78, lines 1-17).

The values in both column VII and column XII of Ex. L-H-SEC-04, Attachment 1 are calculated using average pre-dispatch prices from the IESO's 3-hour ahead pre-dispatch results. These results are available for historical periods and can be used to verify the reasonableness of OPG's decision-making regarding the operation of the PGS. With reference to this information, such verification can be achieved by:

i) Recalculating the break-even pump and generation prices using the formulas described in Ex. L-H-ED-02, part b);
ii) Determining if the pump or generation decision is economic by comparing the applicable break-even prices to the respective pre-dispatch prices available for the evaluated hour; and
iii) Verifying that actual PGS utilization for the evaluated hour aligns with the economic determination from ii).

UNDERTAKING JT1.14

Undertaking

WITH REFERENCE TO COLUMN XI, ADDITIONS TO SBGVA, TO CONFIRM THE CALCULATIONS USED FOR ADDITIONS.

Response

SBGVA additions are calculated at a station level based on forgone production due to SBG conditions multiplied by the approved regulated hydroelectric payment amount less applicable gross revenue charge ("GRC"). In Ex. L-H-SEC-04, Attachment 1, amounts in column xi "Addition to SBGVA" are an aggregation of such SBGVA additions for all stations in a given hour, which may include entries in connection with the Sir Adam Beck facilities that are subject to a GRC rate of $14.40/MWh or other stations that are subject to lower GRC rates.

Additionally, in preparing this response, OPG discovered that an incorrect regulated hydroelectric payment amount value was displayed in column ii of Ex. L-H-SEC-04, Attachment 1 for 2021 and 2022. The $43.15/MWh value shown for those years in column ii should be $43.88/MWh. Values presented in all other columns are unaffected, and there is no impact to any additions made to the SBGVA, which were calculated using the correct approved payment amounts. OPG will file a corrected version of Ex. L-H-SEC-04, Attachment 1.

UNDERTAKING JT1.15

Undertaking

TO PROVIDE DETAIL INCLUDING MATHEMATICAL CALCULATIONS ON THE CALCULATION IN XIII, IN COLUMN P OF THE EXCEL SHEET ENTITLED "ESTIMATED LOSS IF PUMP WAS OPERATED."

Response

OPG understands the undertaking is asking to provide the mathematical calculations for column XII "Estimated loss if pump was operated" of Ex. L-H-SEC-04, Attachment 1, and to advise of any factors that would not allow the calculation to be performed using the information set out at that reference (Tr. Tech. Conf., April 4, 2024, p. 81, lines 21-28, p. 82, line 1).

The economic loss expressed in column XII is dependent on its cause as denoted in the "Reason" column: (i) "Economic Loss due to inability to recover pumping costs" or (ii) "Economic loss due to inability to economically generate." The example below illustrates the calculation of the loss in column XII for the above reason (i). For the above reason (ii), a loss is first calculated for each hour in the next on-peak period using the same formula as shown below, but reflecting forecast revenues calculated using the next on-peak pre-dispatch HOEP for that hour less the average forecast replacement costs. These next on-peak hourly losses are then averaged to derive the forecasted loss associated with the inability to economically generate for the above reason (ii).

Example based on 1/1/18 Hour 14

Compare costs to revenues where:

Sum of costs as shown in columns VIII-X:

= PGS pump costs + SAB I and II opportunity cost[1]

= $[(EF_{PGSPUMP} \times (HOEP + LC)) + (EF_{SAB} \times (HOEP - GRC))] \times EF_{PGSPUMPCMS}$

= $[EF_{PGSPUMP} \times (\$38.08 + LC) + EF_{SAB} \times (\$38.08 - \$14.40)] \times EF_{PGSPUMPCMS}$

= $3,466

Revenues shown in column VII, less GRC cost:

[1] As described in Ex. L-H-SEC-04, part (b), during a pump decision, if pumping the PGS has no downstream impact at SAB I and II, the SAB I and II opportunity cost is set to zero.

= PGS generation revenue + SAB I and II generation revenue[2]
= [EF_{PGSGEN} x (avg on-peak pre-disp HOEP - GRC) + EF_{SAB} x (avg on-peak pre-disp HOEP - GRC)] x $EF_{PGSCMSGEN}$
= [EF_{PGSGEN} x ($42.40 - $5.60) + EF_{SAB} x ($42.40 - $14.40)] x $EF_{PGSCMSGEN}$
= $2,782

Economic loss in column XII: $3,466 - $2,782 = $684

As explained in Ex. L-H-SEC-04 part (b), efficiency factors ("EF") required to perform the above calculations have not been provided in Ex. L-H-SEC-04, Attachment 1 due to commercial sensitivity relating to offer information that could impact OPG as a market participant or competition in the IESO administered market. Similarly, load charges ("LC") have not been provided as providing them would allow the calculation of efficiency factors.

[2] As described in Ex. L-H-SEC-04 part (b), during a generation decision, if generating at the PGS has no downstream impact at SAB I and II, the SAB I and II generation revenue is set to zero.

UNDERTAKING JT1.16

Undertaking

TO PROVIDE THE MATHEMATICAL CALCULATIONS FOR FORECAST REVENUE ACCOUNT COLUMN VII, AND NEXT ON-PEAK PERIOD BEFORE GRP COSTS.

Response

OPG understands that the undertaking refers to “GRC” costs.

The values in column VII “Forecast revenues in next on-peak period (before GRC costs)” of Ex. L-H-SEC-04, Attachment 1 were calculated using the same revenue formula as provided in Ex. JT1.15, with GRC set to zero.

UNDERTAKING JT1.17

Undertaking

TO CLARIFY THAT DURING PERIODS OF SBG OPG WOULD NOT HAVE PUMPED THE PGS, NOT HAVE UTILIZED THE PGS MORE.

Response

OPG understands this undertaking to be a request to clarify whether, during periods of surplus baseload generation ("SBG"), OPG would have utilized the Sir Adam Beck Pump Generating Station ("PGS") more if OPG's hydroelectric incentive mechanism ("HIM") revenues were not shared (Tr. Tech. Conf., April 4, 2024, p. 84, lines 17-21).

For the periods for which OPG is seeking disposition of SBGVA balances in this proceeding, HIM revenue sharing did not impact PGS utilization and the PGS would not have been utilized more in the absence of such sharing because the HIM revenues remained below the Hydroelectric Incentive Mechanism Variance Account sharing threshold.[1]

[1] As described at Ex. H1-1-1, p. 8, the Hydroelectric Incentive Mechanism Variance Account "records a credit to ratepayers of 50% of OPG's HIM revenues above an OEB-specified threshold, currently set at $54.5M based on the forecast of HIM revenues reflected in the hydroelectric payment amounts approved in EB-2013-0321." Actual HIM revenues, as presented in Ex. L-M-SEC-08, Chart 1, remained below the OEB-specified threshold amount in the applicable years.

UNDERTAKING JT1.18

Undertaking

TO PROVIDE A MORE DETAILED RESPONSE FOR IR IESO-02B, ON THE MEANING OF "BEING CONSTRAINED OFF AS A RESULT OF THE OPERATION OF THE MARKET."

Response

OPG understands this undertaking to refer to OPG's response in Ex. L-M-IESO-02, part a), where OPG stated:

> 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.

OPG's reference to "operation of the market" in the response was broad and intended to capture the impact of physical constraints of the power system that are present during the operation of the market, as distinguished from factors within OPG's control as captured by the reference to "its [OPG's] operation of the prescribed facilities".

UNDERTAKING JT1.19

Undertaking

TO PROVIDE A MORE DETAILED RESPONSE TO STAFF-23.

Response

OPG understands this undertaking to be a request for whether the back-test method described in Ex. L-M-SEC-06, or the forecast method described in Ex. L-M-SEC-10, could be used to provide a more detailed response to Ex. L-M-Staff-23, which asked for a quantification of the impact on the SBGVA additions in the new market design under Market Renewal (Tr. Tech. Conf., April 4, 2024, p. 101).

The back-test method described in Ex. L-M-SEC-06 can only approximate how the SBGVA balances would have differed in a historical period if entries were made under the SBGVA methodology proposed in this proceeding for the new market design. Since historical spill amounts are not indicative of the future and, as discussed in Ex. L-M-Staff-23, do not reflect efficiencies of reduced spill that are expected in the new market, this method is not appropriate for approximating impacts on the SBGVA on a forward-looking basis.

Regarding the forward-looking total customer cost analysis provided in Ex. L-M-SEC-10, OPG's model is unable to discern between local and global curtailment amounts. As explained in Ex. L-M-IESO-03, the model considers SBGVA additions by including both local and global spill amounts in both modelled scenarios. Hence, OPG's total customer cost modelling approach is unable to and does not model the difference between the current SBGVA methodology and the proposed SBGVA methodology for the new market design.

UNDERTAKING JT1.20

Undertaking

TO PROVIDE A FURTHER RESPONSE TO L-H-ED-08, USING IESO DATA FOUND AT THE IESO POWER DATA DIRECTORY; IF THIS IS NOT POSSIBLE, TO EXPLAIN WHY.

Response

The information requested in this undertaking is not relevant to assessing the recoverability of the requested balances in the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") or any other issue before the OEB in this proceeding.

The SBGVA records the financial impact of foregone production resulting from SBG conditions in accordance with the OEB's decisions and orders. In support of the amounts sought through the SBGVA, OPG has provided evidence in this proceeding regarding the basis for its decision-making with respect to PGS utilization during the times for which entries have been made to the SBGVA. The status of gas generation facilities at a time when such entries were made is not relevant to OPG's compensation for foregone hydroelectric production resulting from SBG conditions through the SBGVA because market operations including generator dispatch are in the purview of the IESO and not OPG. The IESO manages SBG conditions as an element of ensuring the reliability and efficiency of Ontario's power grid. As discussed in section 2.4 of the SBG Study (Ex. M1-1-1, Attachment 1), during periods of SBG, the IESO utilizes a "dispatch order for baseload generation which will produce real-time dispatch outcomes that promote market efficiency, achieve cost-effectiveness, [and] minimize environmental impacts".

UNDERTAKING JT1.21

Undertaking

FOR EACH HOUR WHERE WATER IS BEING SPILT AND GAS IS OPERATING IN THE PROVINCE, CAN YOU PROVIDE A TABLE THAT NAMES THE HYDRO FACILITIES RESPONSIBILITY FOR THE SBGVA ENTRIES AND THE NAME OF THE GAS GENERATORS THAT ARE RUNNING IN THOSE HOURS, SUBJECT TO BEING ABLE TO FIND THE NECESSARY DATA IN THE ONLINE IESO POWER DATA DIRECTORY, WITH THE SAME CAVEATS AS GIVEN IN JT1.20.

Response

Refer to Ex. JT1.20.

UNDERTAKING JT1.22

Undertaking

TO CONFIRM WHETHER OPG IS AWARE OF CIRCUMSTANCES OR SITUATIONS WHEN HYDROELECTRIC SPILL IS OCCURRING WHEN GAS-FIRED GENERATION IS RUNNING.

Response

OPG can only speculate as to the reasons why gas-fired generation is running while hydroelectric spill is occurring, as such analysis requires access to the IESO's dispatch algorithm and dispatch data. Based on OPG's experience in operating in the Ontario market, below are some examples of circumstances when gas-fired generation may be running while OPG is foregoing generation in the form of hydroelectric spill as a result of SBG conditions. OPG notes that this list is not intended to be exhaustive.

- **Operational Constraints:** Gas-fired generation facilities have operational constraints such as minimum run times representing the duration gas units must be online in order to ramp to a minimum loading point and meet the facility's minimum generation block run-time.
- **System Reliability:** Gas-fired generation facilities play an important role in maintaining system reliability. At times, these facilities are online at minimum loading points to be available to respond to ramping requirements for hourly changes in variable generation such as wind and solar.
- **Cogeneration Facilities:** Cogeneration facilities produce both electricity and steam for downstream processes and often run continuously.
- **Testing:** Gas-fired generation facilities may be required to perform periodic testing.
- **Local Reliability Needs:** Gas-fired generation facilities may be required to be online at minimum loading points in order to meet local needs.