BUSINESS PLANNING AND BENCHMARKING - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the regulated hydroelectric business plan and benchmarking and provides a summary of the regulated hydroelectric operating costs.

2.0 OVERVIEW

A summary of the operating costs for 2010 - 2015 is presented in Ex. F1-1-1 Table 1 for the Niagara Plant Group and R.H. Saunders GS, and in Ex. F1-1-1 Table 2 for the newly regulated hydroelectric facilities.

Actual and planned regulated hydroelectric OM&A (Base and Project) expenditures increase by an average of 2.6 per cent /year over the 2010 to 2015 period. A large number of OPG's regulated hydroelectric facilities continue to benchmark well (i.e., top two quartiles) for safety, environmental performance, costs, reliability and availability.

Excluding extraordinary items described in Ex. F1-2-1, section 3 and the Business Transformation re-organization described in Ex. A4-1-1 and A1-4-2, section 4.1, increases in total OM&A are mostly due to labour cost escalation and additional maintenance and project work. The project work includes the start of several major unit overhauls and other structural rehabilitation projects (see Ex.F1-3-1).

The regulated hydroelectric forecasts for the test period are from OPG's 2013 - 2015 Business Plan. The business plan is discussed in section 3.0. Section 4.0 presents the regulated hydroelectric performance targets and section 5.0 presents the regulated hydroelectric benchmarking results.

3.0 REGULATED HYDROELECTRIC BUSINESS PLAN

The Hydro Thermal Operations ("HTO") Business Plan (which includes the regulated hydroelectric operations) is prepared annually as part of the corporate business planning and budgeting process described in Ex. A2-2-1. The HTO business planning process is focused on identifying the initiatives, programs, projects and resources required to achieve safety, environmental, operational, financial, and new development business objectives. The HTO business planning process is generally the same as that presented in EB-2010-0008, Ex. F1-1-1, and is described in Appendix A.

The 2013 - 2015 HTO Business Plan is provided in Attachment 1. Discussion of specific initiatives contained in the business plan and their impact on operational and financial performance can be found in the evidence on base OM&A (Ex. F1-2-1), project OM&A (Ex. F1-3-1), capital projects (Ex. D1-1-1), and the production forecast (Ex. E1-1-1).

OPG is in the midst of a Business Transformation ("BT") program in order to improve its cost structure, and to design a more efficient and effective organization.

The strategy and key initiatives for the regulated hydroelectric facilities in the 2013-2015 Business Plan in the areas of ongoing operations and investments in long-term energy supply are presented below.

<u>Ongoing Operations</u>

- Continue prudent and economic investment to sustain and improve the existing hydroelectric assets for the long term. These investments have been prioritized using a portfolio approach (described in Appendix A) with a focus on maintaining reliability, regulatory compliance, safety and structural integrity of the high value assets. Lower priority projects have been deferred to the post 2015 period.
- Focus on regulatory and sustaining work during planning period. Value enhancing projects are to be performed where prudent or deferred to the post 2015 period.
- Utilize a differentiated maintenance strategy (Streamlined Reliability Centred Maintenance) to target maintenance work at delivering high reliability at stations

with a high value to OPG. Availability of OPG's large hydroelectric stations is targeted to be in the top quartile of EUCG (formerly known as Electric Utility Cost Group) and CEA (Canadian Electrical Association) benchmarking.

- Improve safety performance and maintain excellent environmental performance.

Development Initiatives

- The Niagara Tunnel Project has been completed ahead of the approved schedule and approximately $100M lower than budget. The energy production at the existing Sir Adam Beck stations will increase by an average 1.5 TWh per year (see Ex. D1-2-1).
- Continue preparations for the Sir Adam Beck PGS reservoir rehabilitation project. This project, which is scheduled to start in 2016, is necessary to ensure the safety and the ongoing viability of the PGS station (see Ex. D1-1-2).
- Continue with the Ranney Falls Expansion project that will add up to 10 MW of capacity to the existing generating station (see Ex. D1-1-2).

4.0 HYDROELECTRIC KEY PERFORMANCE TARGETS

Hhydroelectric establishes performance targets to support its business objectives as part of the business planning process. Benchmarking, as discussed in section 5.0, is one tool used in target setting and Hydroelectric benchmarks its performance against these targets. Hydroelectric monitors and compares targets to actual data as the year progresses.The main hydroelectric performance targets are more fully described in Appendix B and consist of:

- Availability
- Equivalent Forced Outage Rate
- OM&A Unit Energy Cost
- Safety – All Injury Rate
- Environmental Performance

4.1 Performance Targets

4.1.1 Availability and Equivalent Forced Outage Rate ("EFOR") - History and Targets

Charts 1a and 1b show reliability targets and actual performance from 2010 - 2012 for each of OPG's large regulated hydroelectric stations (i.e., greater than 10MW), and the totals of all regulated stations grouped by large and small plants.

Overall, from 2010 through 2012, the availability of most of the large stations was on or better than target.

Chart 1a

Regulated Hydroelectric Facilities - History and Targets for Availability (%)

Station / Group Name	2010 Target	2010 Actual	2011 Target	2011 Actual	2012 Target	2012 Actual
DeCew Falls 2 GS	90.2	95.9	94.6	96.9	95.4	95.1
Sir Adam Beck 1 GS	79.3	82.8	83.5	84.2	80.5	78.2
Sir Adam Beck 2 GS	94.3	95.4	95.6	95.5	96.7	95.3
Sir Adam Beck Pump GS	82.3	95.8	79.8	78.4	80.6	92.6
R.H. Saunders GS	93.7	93.8	89.1	90.1	93.7	93.2
Niagara & Saunders	**89.9**	**92.8**	**89.4**	**89.7**	**90.9**	**91.4**
Abitibi Canyon GS	82.3	79.7	91.3	87.1	92.7	94.9
Lower Notch GS	94.8	85.4	94.0	94.2	81.8	81.0
Otter Rapids GS	93.3	95.2	93.3	92.3	93.3	94.2
Northeast PG	**88.6**	**86.4**	**92.5**	**90.3**	**90.9**	**92.2**
Aguasabon GS	95.5	94.0	92.1	94.5	93.4	91.8
Alexander GS	88.8	84.5	90.6	90.5	92.3	91.8
Cameron Falls GS	97.6	96.6	94.8	94.1	97.7	98.9
Caribou Falls GS	91.9	99.1	95.1	92.7	93.0	96.6
Kakabeka Falls GS	89.9	93.3	91.2	92.3	96.8	93.8
Manitou Falls GS	96.7	97.0	92.1	96.3	96.3	95.0
Pine Portage GS	92.2	97.2	97.3	97.2	86.8	88.5
Silver Falls GS	93.5	97.4	82.1	85.0	93.8	89.4
Whitedog GS	87.9	82.2	86.9	84.8	90.7	84.0
Northwest PG	**93.0**	**93.4**	**92.5**	**92.8**	**93.9**	**93.2**
Arnprior GS	85.4	97.0	82.1	77.8	76.6	74.3
Barrett Chute GS	82.8	96.2	80.3	85.5	83.5	79.1
Chats Falls GS	88.8	87.3	93.2	93.3	91.5	91.2
Chenaux GS	93.8	93.8	93.2	94.0	89.1	89.8
Des Joachims GS	92.3	91.3	91.7	92.0	91.9	92.0
Mountain Chute GS	67.4	56.8	59.8	67.4	70.3	70.5
Otto Holden GS	91.0	93.4	95.0	95.2	91.9	92.4
Stewartville GS	88.5	95.8	93.7	96.5	86.8	90.6
Ottawa St. Lawrence PG	**89.0**	**91.1**	**90.2**	**91.4**	**88.4**	**88.6**
Newly Reg. - large plants	**90.5**	**91.4**	**91.3**	**91.8**	**90.8**	**90.7**
CHPG - small plants			**87.7**	**87.9**	**89.8**	**87.6**

Notes:

- High availability factor is good.

Chart 1b

Regulated Hydroelectric Facilities - History and Targets for EFOR (%)

Station/ Group Name	2010 Target	2010 Actual	2011 Target	2011 Actual	2012 Target	2012 Actual
DeCew Falls 2 GS	2.6	0.2	1.0	0.1	0.8	2.8
Sir Adam Beck 1 GS	3.5	0.6	3.1	1.0	3.1	6.9
Sir Adam Beck 2 GS	0.2	0.2	0.2	0.4	0.3	0.4
Sir Adam Beck Pump GS	4.8	1.2	5.1	11.3	5.1	6.9
R.H. Saunders GS	0.4	0.2	0.4	0.4	0.4	0.0
Niagara & Saunders	**1.3**	**0.3**	**1.1**	**1.2**	**1.2**	**2.1**
Abitibi Canyon GS	2.7	3.9	3.3	1.4	3.4	1.4
Lower Notch GS	2.9	23.0	2.4	3.1	3.3	0.1
Otter Rapids GS	2.6	4.1	2.8	4.9	2.9	1.3
Northeast PG	**2.7**	**7.3**	**3.0**	**2.9**	**3.2**	**1.2**
Aguasabon GS	0.6	1.2	1.0	0.2	1.1	0.8
Alexander GS	0.5	0.1	0.4	0.5	0.3	0.1
Cameron Falls GS	1.0	0.6	0.7	0.9	0.7	0.4
Caribou Falls GS	0.6	0.0	0.5	0.1	0.5	0.1
Kakabeka Falls GS	1.8	3.0	1.7	0.5	1.7	1.3
Manitou Falls GS	0.7	0.5	0.5	1.0	0.5	0.5
Pine Portage GS	0.5	0.1	0.4	2.1	0.3	0.2
Silver Falls GS	0.4	1.0	0.3	0.6	0.3	1.5
Whitedog GS	0.8	1.8	0.5	1.8	0.5	10.3
Northwest PG	**1.0**	**0.8**	**1.0**	**0.9**	**1.0**	**1.3**
Arnprior GS	2.5	1.1	1.3	0.0	1.4	7.3
Barrett Chute GS	11.7	2.7	6.5	8.0	3.0	8.8
Chats Falls GS	3.1	0.8	1.5	0.7	1.2	1.4
Chenaux GS	1.4	0.2	0.7	0.0	0.6	0.1
Des Joachims GS	0.9	1.0	0.3	0.1	0.4	0.5
Mountain Chute GS	13.9	41.6	9.4	1.0	5.0	3.7
Otto Holden GS	0.9	0.3	0.4	0.3	0.4	0.4
Stewartville GS	5.8	6.3	2.5	0.9	3.0	2.5
Ottawa St. Lawrence PG	**2.6**	**2.5**	**3.5**	**0.8**	**2.4**	**1.2**
Newly Reg. - large plants	**1.9**	**2.4**	**2.4**	**1.1**	**1.8**	**1.3**
CHPG - small plants			**4.3**	**3.4**	**3.4**	**5.2**

Notes:

- Low EFOR is good.

As described in Appendix A, HTO uses a structured portfolio approach to the management of its generating stations. For OPG's larger hydroelectric plants, an average availability target of between 90 per cent and 94 per cent is considered acceptable over the business planning period. These targets are in excess of CEA and EUCG benchmarking averages. For the small plants under 10 MW, availability targets between 85 per cent and 90 per cent are considered acceptable depending on the capacity factor of the station.

Charts 2a and 2b show availability and EFOR targets for the 2013 - 2015 Business Plan period. Availability targets and actuals deviate from the long term targets described above due to planned outage programs, as well as forced outages which cannot be predicted. Overall, availability is expected to be between 90.8 per cent and 92.9 per cent for the regulated large plants and between 85 per cent and 90.5 per cent for the regulated small plants.

Chart 2a

Availability Targets (%)

Station / Group Name	2013 Target	2014 Target	2015 Target
DeCew Falls 2 GS	89.9	95.4	94.2
Sir Adam Beck 1 GS	89.3	84.9	84.9
Sir Adam Beck 2 GS	95.0	96.7	98.2
Sir Adam Beck Pump GS	73.6	79.0	76.2
R.H. Saunders GS	93.8	93.7	94.0
Niagara PG & Saunders GS	90.8	91.5	91.6
Northeast PG	90.3	87.4	87.9
Northwest PG	93.3	95.2	97.5
Ottawa St. Lawrence PG	90.9	92.2	86.3
Newly Regulated - large plants	92.0	92.9	92.2
Central Hydro PG - small plants	88.8	84.5	90.5

Chart 2b

EFOR Targets (%)

Station/ Group Name	2013 Target	2014 Target	2015 Target
DeCew Falls 2 GS	0.7	0.7	0.7
Sir Adam Beck 1 GS	3.3	3.3	3.4
Sir Adam Beck 2 GS	0.3	0.3	0.3
Sir Adam Beck Pump GS	6.7	6.7	6.8
R.H. Saunders GS	0.6	0.6	0.6
Niagara PG & Saunders GS	1.4	1.4	1.4
Northeast PG	3.8	3.8	3.8
Northwest PG	1.0	1.0	1.0
Ottawa St. Lawrence PG	1.4	1.4	1.4
Newly Regulated - large plants	1.6	1.6	1.6
Central Hydro PG - small plants	3.3	3.2	3.4

4.1.2 <u>OM&A Unit Energy Cost - History and Targets</u>

Chart 2c shows OM&A unit energy cost ("UEC") targets for 2010 – 2015 for the regulated hydroelectric stations. These targets are calculated using planned OM&A expenditures, divided by the energy forecast for each year**.** More details on the factors affecting unit energy costs are discussed in section 4.2 below.

Actual OM&A UEC performance for both Niagara and R.H. Saunders for 2010 and 2011, was better than target due to lower than planned OM&A spending. n 2012, performance was worse than target due to lower than expected water inflows and associated lower energy production. Future unit energy cost targets are expected to be higher than historical figures due to higher OM&A costs for both base and project work, combined with lower than historical inflows affecting production, partially offset by increased production due to the in-service of the Niagara Tunnel project.

Actual OM&A UEC performance for the newly regulated stations from 2010 to 2012, was worse than target due to lower than historical water inflows, station outages, and First

Nations settlement provisions and projects. Future unit energy cost targets are in line with historical figures as inflows are projected to increase to historical averages, while costs increase for both base and project OM&A.

Chart 2c

OM&A Unit Energy Cost Targets ($/MWh)

Plant Group	2010 Target	2010 Actual	2011 Target	2011 Actual	2012 Target	2012 Actual	2013 Target	2014 Target	2015 Target
Niagara PG	4.1	4.0	4.7	3.2	4.1	4.8	5.2	5.2	4.5
Saunders GS	2.3	2.4	2.6	2.4	2.8	2.4	3.4	3.5	3.8
Total - Niagara & Saunders	3.5	3.4	4.0	2.9	3.6	4.0	4.6	4.6	4.3
Ottawa St.Lawrence PG	7.6	8.7	8.5	7.5	8.2	8.8	8.1	8.2	10.0
Central Hydro PG	53.5	45.4	53.1	52.3	48.0	50.5	52.8	64.6	58.1
Northeast PG	12.5	20.9	9.4	11.9	10.9	12.0	11.3	12.8	12.0
Northwest PG	8.1	13.9	8.4	10.4	7.9	9.7	7.6	8.2	8.1
Total - Newly Regulated	10.6	14.0	10.5	11.1	10.4	11.3	10.4	11.1	11.7

Note: Above OM&A Unit Energy costs are consistent with OEB filing guidelines: SBG, NYPA water transactions, and related Gross Revenue Charge are excluded from the target levels. Northwest PG 2010 OM&A costs include a $11.3M First Nations settlement provision, and $9M of shoreline remediation projects for other First Nations.

4.1.3 Safety – All Injury Rate - History and Targets

The All Injury Rate (“AIR”) replaced the Accident Severity Rate (“ASR”) in 2012 as the key safety performance measure. Chart 2d shows the All Injury Rate actual performance and targets from 2010 - 2016. These targets are generally based on CEA benchmarking, as well as OPG’s overall targets. Combined (total Hydroelectric), the plant groups met the AIR targets in 2010 and 2012, but did not meet the target in 2011.

Chart 2d

All Injury Rate (number of medical treatment injuries /200,000 hours worked)

Plant Group	2010		2011		2012		2013-2016
	Target	Actual	Target	Actual	Target	Actual	Target
Niagara	2.50	0.96	1.54	0.00	1.66	1.01	1.56
Ottawa St. Lawrence (incl. Saunders)	2.50	1.30	1.54	2.52	1.66	1.28	1.56
Northeast	2.50	1.51	1.54	3.31	1.66	2.49	1.56
Northwest	2.50	5.78	1.54	1.60	1.66	1.65	1.56
Central Hydro	2.50	2.00	1.54	0.91	1.66	0.00	1.56
Hydro Total	2.50	1.98	1.54	1.78	1.66	1.40	1.56

Note: The above AIR statistics are Plant Group totals that include both regulated and unregulated stations.

4.1.4 Environmental Performance Index – History and Targets

Hydro Thermal Operations has a very good track record with regard to environmental performance. Environmental management systems have been in place since 2000 and have been registered under the International Organization of Standardization ("ISO") 14001. In 2009, the Niagara Plant Group was designated as an Environmental Leader by the Ontario Ministry of Environment ("MOE"). The Niagara Plant Group was the first in the electricity sector to receive this designation. The Niagara Plant Group and R.H Saunders have also been recognized by the Wildlife Habitat Council over the past several years for their various biodiversity programs.

The environmental performance index ("EPI") includes a variety of measures and deliverables, some that are specific targets (such as minimizing the number of spills and MOE infractions) and some that are environmental initiatives (such as compliance cost management, Endangered Species Act, etc.). The EPI target is 1.0. An EPI above 1.0 can only be achieved if the number of spills and infractions are less than target, and/or the number of energy efficiency initiatives is better than planned. For the Hydroelectric facilities, the actual EPI has been better than the target of 1.0 from 2010 - 2012. The EPI target for 2013 - 2015 continues to be 1.0.

5.0 REGULATED HYDROELECTRIC FACILITIES BENCHMARKING

Hydro Thermal Operations benchmarks reliability, cost and safety performance with comparable businesses to assess and understand the performance of its stations, as well as to identify and share best practices and opportunities for improvement. However, because of differing geography, the distribution of plants across the province, water conditions, as well as differences in regulatory regimes and station age, design, size, and infrastructure (dams, bridges, etc), absolute comparisons cannot be made between OPG's regulated hydroelectric station costs and those of other utilities.

Hydro Thermal Operations reviews benchmarking results and best practices annually as part of the business planning process and applies new practices and cost/efficiency improvements as appropriate.HTO also has participated in informal benchmarking activities with various utilities in the past to identify actions that ultimately may result in cost efficiencies, and operational and maintenance improvements. Examples of best practices that have been implemented include:

- Station automation,
- Use of a risk-based instead of a time-based maintenance approach (streamlined reliability-centred maintenance),
- Overtime reductions from 11 per cent of labour cost in 2001 to under 6 per cent in the 2010 – 2015 period (see Ex. F1-2-1),
- A transition to skill broadening in some locations (i.e., trades learn more than one discipline),
- Implementation of "lead plant" concept for some aspects of governance in order to minimize duplication of effort.

Hydro Thermal Operations uses three main sources for hydroelectric benchmarking:

- EUCG Inc. ("EUCG", formerly known as Electric Utility Cost Group)
- Navigant Consulting (GKS Hydro Benchmarking)
- Canadian Electrical Association ("CEA")

5.1 Availability and Equivalent Forced Outage Rate

Hydroelectric benchmarks reliability using Availability and Equivalent Forced Outage Rate ("EFOR") data from the EUCG and the CEA. The results of the 2009 - 2011 reliability benchmarking of the regulated hydroelectric facilities are presented in Charts 3a, 3b and 3c.

Hydro Thermal Operations has participated in the Generation Equipment Reliability Information System benchmarking programs carried out by EUCG and the CEA since the mid 1990s. EUCG benchmarking includes participation by Canadian and American utilities, including Manitoba Hydro, New Brunswick Power, Hydro-Quebec, Pacific Gas & Electric, U.S. Army Corps of Engineers, Tennessee Valley Authority, Seattle City and Light, and Bonneville Power Authority. For this benchmarking, the data are not aggregated, thus individual OPG plants can be compared to the individual plants in the entire group (i.e., "quartile" analysis can be done).

Fourteen Canadian utilities participate in the CEA reliability benchmarking, including Manitoba Hydro, BC Hydro, Newfoundland and Labrador Hydro, Nova Scotia Power, Saskatchewan Power, New Brunswick Power, Fortis, Capital Power, and others. The CEA benchmarking is done on an aggregate basis by utility. Aggregated results for OPG plants are compared to the aggregated results of the plants in the entire group of utilities.

OPG's small (i.e., less than 10 MW), run-of-the-river generating stations are excluded from benchmarking because they are self-dispatchable, connected to local distribution, and have no impact on the reliability of bulk electricity system. Collectively, these stations comprise approximately two per cent of OPG's total hydroelectric capacity and average annual energy production.

5.1.1 EUCG Availability and Reliability, Niagara Plant Group Stations and R.H. Saunders GS

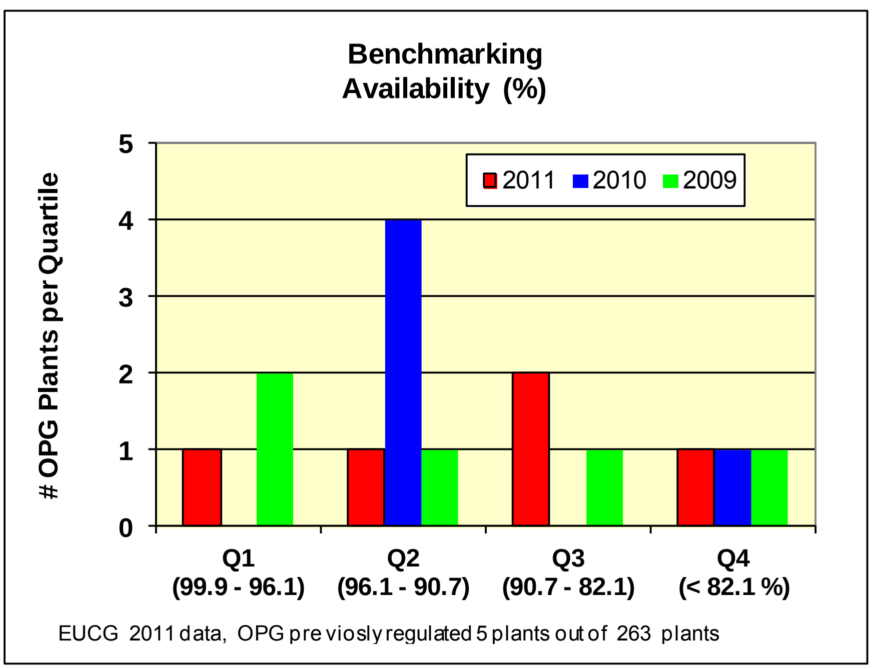
Charts 3a and 3b present the EUCG quartile ranking for availability and reliability (as measured by EFOR) for the Niagara Plant Group stations and R.H. Saunders GS. Except as noted below, from 2009 - 2011, OPG's Niagara Plant Group stations and R.H. Saunders GS have performed better than the EUCG average benchmarks, ranking in the top two quartiles for availability and reliability.

As described in EB-2010-0008, the Sir Adam Beck Pump Generating Station ("PGS") is inherently less reliable, and therefore ranks lower than conventional hydroelectric generation. This is due to the PGS' older, technically complex, reversible pump turbine design, and its multi-faceted role in the electricity system (e.g., pumping, generating, automatic generation control, and water diversion control).

Performance at Sir Adam Beck I slipped below average into the third quartile due to the age and poor condition of the station's unrehabilitated units and long planned outages for the major unit rehabilitation/upgrade program. To date, work on Units 3, 7 and 9 has been completed. The availability and reliability of the station is expected to improve significantly after the remaining operating units have been rehabilitated and upgraded.

Chart 3a

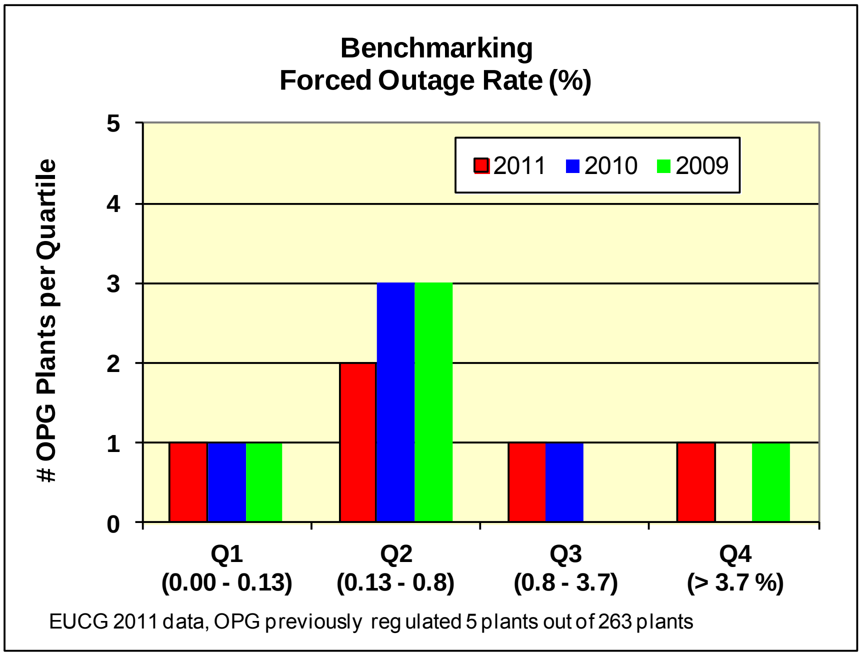
EUCG Availability Benchmarking – Niagara and Saunders



Note: 80% of Energy Production is in Q1/Q2 (3 year avg.)

Chart 3b

EUCG EFOR Benchmarking – Niagara and Saunders

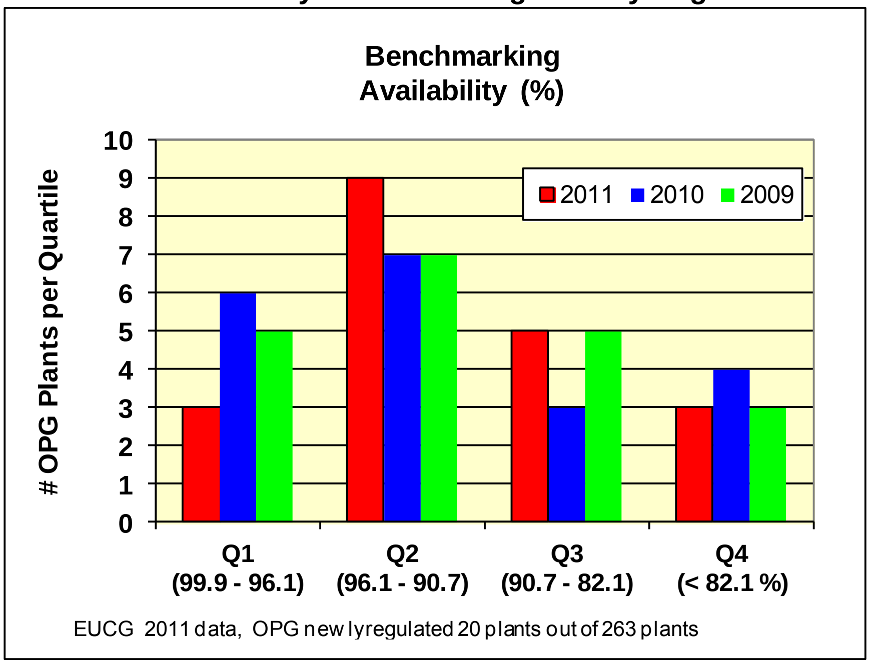


Note: 96% of Energy Production is in Q1/Q2 (3 year avg.)

5.1.2 <u>EUCG Availability and Reliability, Newly Regulated Hydroelectric Stations</u>

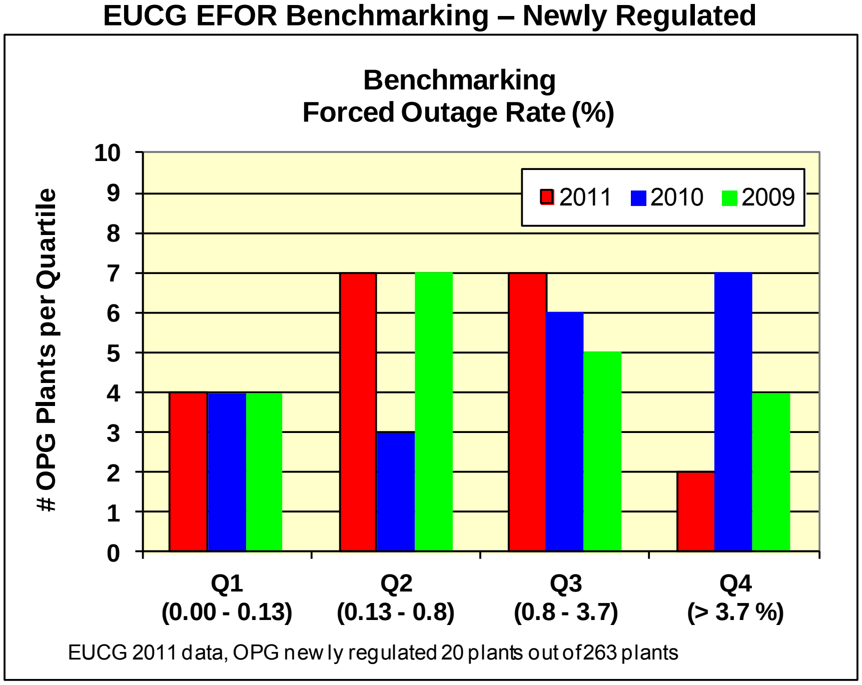
Charts 3c and 3d present the EUCG quartile ranking for availability and reliability (as measured by EFOR). From 2009 - 2011, most of OPG's newly regulated stations have performed better than the EUCG average benchmarks, ranking in the top two quartiles for availability and reliability.

Chart 3c
EUCG Availability Benchmarking – Newly Regulated



Note: 67% of Energy Production is in Q1/Q2 (3 year avg.)

Chart 3d
EUCG EFOR Benchmarking – Newly Regulated



Note: 67% of Energy Production is in Q1/Q2 (3 year avg.)

5.1.3 Canadian Electrical Association Availability and Reliability Benchmarks

Chart 3e presents aggregated CEA benchmarking data for availability and reliability ("EFOR"). Except where noted, the results demonstrate that the availability and reliability for the Niagara Plant Group and R.H. Saunders GS, and the newly regulated hydroelectric facilities are better than the CEA benchmarks. The main exceptions are in the Northeast Plant Group where:

- The 80 year old Abitibi Canyon GS experienced a full station outage in 2010 to rehabilitate/rebuild its deteriorated tailrace piers and to perform electrical upgrades.
- A failure of a generator winding at Lower Notch GS necessitated significant repairs and a 3 month outage.
- Outages at Otter Rapids GS for transformer and digital protections upgrades.

Chart 3e

CEA Reliability Benchmarking

Measure	Group Name	2009	2010	2011	2012
Equivalent Availability Factor (%)	CEA (excluding OPG)	91.1	89.7	87.1	88.2
	Niagara PG & Saunders GS	93.6	92.8	89.7	91.4
	Northeast PG	85.8	86.4	90.3	92.2
	Northwest PG	92.8	93.4	92.8	93.2
	Ottawa St.Lawrence PG	92.9	91.1	91.4	88.5
	OPG Newly Regulated	92.6	91.9	91.1	91.0
Equivalent Forced Outage Rate (%)	CEA (excluding OPG)	2.2	5.1	6.7	6.3
	Niagara PG & Saunders GS	1.0	0.3	1.2	2.1
	Northeast PG	5.7	7.3	2.9	1.2
	Northwest PG	0.8	0.8	0.9	1.3
	Ottawa St.Lawrence PG	1.7	2.5	0.7	1.2
	OPG Newly Regulated	1.5	1.6	1.1	1.6

Notes:
High Availability is good and low EFOR is good
Availability Factor and EFOR are unit-weighted
Composite measures based on: (1) CEA - 310 units; (2) Niagara & Saunders - 48 units; (3) OPG Newly Regulated - 100 units

5.2 OM&A Unit Energy Cost

Hydro Thermal Operations benchmarks OM&A cost performance at Niagara Plant Group and R.H. Saunders stations through participating in Navigant Consulting's Hydroelectric Generation Benchmarking Program. The Navigant benchmarking program includes a best practices and data review workshop held annually with participants. Hydro Thermal Operations also participates in EUCG's annual OM&A benchmarking program that includes all the large, newly regulated stations.

5.2.1 Navigant Unit Energy Cost Benchmarking

The Navigant Consulting Unit Energy Cost Benchmarking participants are comprised of Canadian and U.S. utilities and include BC Hydro, Nova Scotia Power, Great Lakes Power, TransAlta Utilities, Newfoundland and Labrador Hydro, the Tennessee Valley Authority, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, Southern California Edison, and Chelan County PUD. The hydroelectric stations in this group of utilities are diverse in size, type, location and age, and include a mix of run-of-the-river, peaking, and pumped storage stations.

Costs included in the Navigant Consulting unit energy cost benchmarking pertain to operations, plant maintenance, waterways and dams, and other maintenance, support (i.e., engineering, finance, corporate support), and public affairs and regulatory. Public affairs and regulatory costs include items such as water rentals and usage fees, gross revenue charge, major environmental costs such as fish/wildlife operations and studies, as well as special licensing fees (e.g., FERC re-licensing in the U.S.). The cost benchmarking data presented are for OM&A costs only, and excludes items such as project spending and regulatory costs.

The results of the Navigant Consulting OM&A unit energy cost benchmarking programs are summarized in Chart 4**.** The Navigant study results are segmented into various peer groupings. Cost drivers used to determine peer groupings include unit/station sizes, number of units, and age. The cost benchmarking results from 2009 - 2011 show that, collectively, the Niagara Plant Group and R.H. Saunders facilities are in the top quartile.

Chart 4

Navigant Consulting Hydroelectric Benchmarking Results (USD/MWh)

Station / Group Name	2009	2010	2011	Quartile	Peer Group (Navigant 2011 data)
DeCew Falls I	Not Available (outage all 2009)	Not Available (outage all 2010)	50.7 (Q4)	Q4: 23.4 to 86.5	37 micro plants (< 30 MW)
DeCew Falls II	3.3 (Q1)	3.0 (Q1)	3.1 (Q1)	Q1: 2.0 to 5.2	55 small plants (30 to 150 MW)
SAB I	6.5 (Q4)	8.0 (Q4)	9.1 (Q4)	Q4: 5.5 to 9.1	13 med-large plants (400 to 700 MW)
SAB II	1.7 (Q1)	1.96 (Q1)	2.0 (Q2)	Q2: 2.0 to 2.5	27 large plants (700 MW or more)
SAB PGS	65.2 (Q4)	90.1 (Q4)	128.2 (Q4)	Q4: 28.1 to 140.3	16 PGS plants
Saunders	2.2 (Q2)	2.65 (Q2/3)	2.4 (Q2)	Q2: 2.0 to 2.5	27 large plants (700 MW or more)
OPG plants (excl. PGS)	2.4 (Q1)	2.76 (Q1)	2.9 (Q1)	Q1: 0.6 to 3.9	186 plants
OPG plants (incl. PGS)	2.8 (Q1)	3.2 (Q1)	3.4 (Q1)	Q1: 0.6 to 4.0	210 plants

Notes:

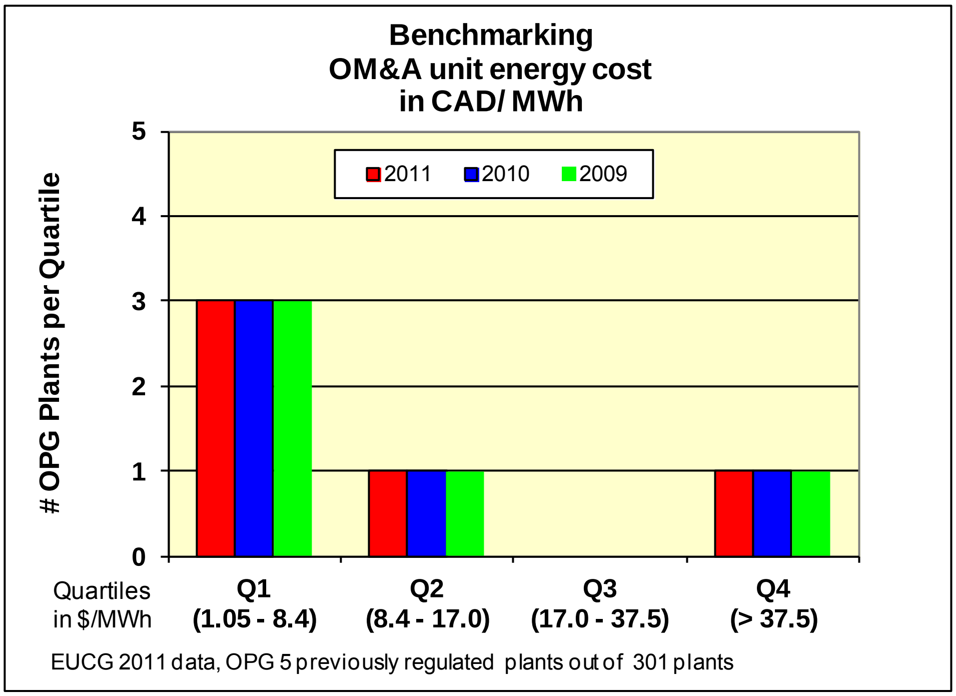
- The above energy costs exclude: gross revenue charges, water rental fees, and capital and OM&A investment costs. Hydro common cost and corporate allocations are included
- Plant labour costs are normalized to US rates using Regional Wage Adjusters for skilled Trades.
- The costs are expressed in US dollars using International Monetary Fund report (International Financial Statistics). The following factors have been applied to 2009 = 0.85631, 2010 = 0.96562, 2011 = 1.01516
- In 2009 and 2010 DeCew Falls I was out of service. In these years, it is excluded form composite indices (OPG index)

5.2.2 EUCG Unit Energy Cost Benchmarking

The results of the EUCG OM&A unit energy cost benchmarking programs are summarized in Chart 5a for the Niagara Plant Group and R.H. Saunders GS, and in Chart 5b for the newly regulated facilities. Participants in EUCG benchmarking are the same as those described for reliability benchmarking in section 4.0.

Chart 5a shows the EUCG quartile ranking for OM&A unit energy costs of the Niagara Plant Group stations and R.H. Saunders GS. These stations have generally been better than the EUCG average benchmarks over the 2009 - 2011 period. Over the three year period, an average of 99 per cent of the energy production from these facilities has been ranked has ranked the top two quartiles.

Chart 5a
EUCG Unit Energy Cost Benchmarking Results - Niagara and Saunders

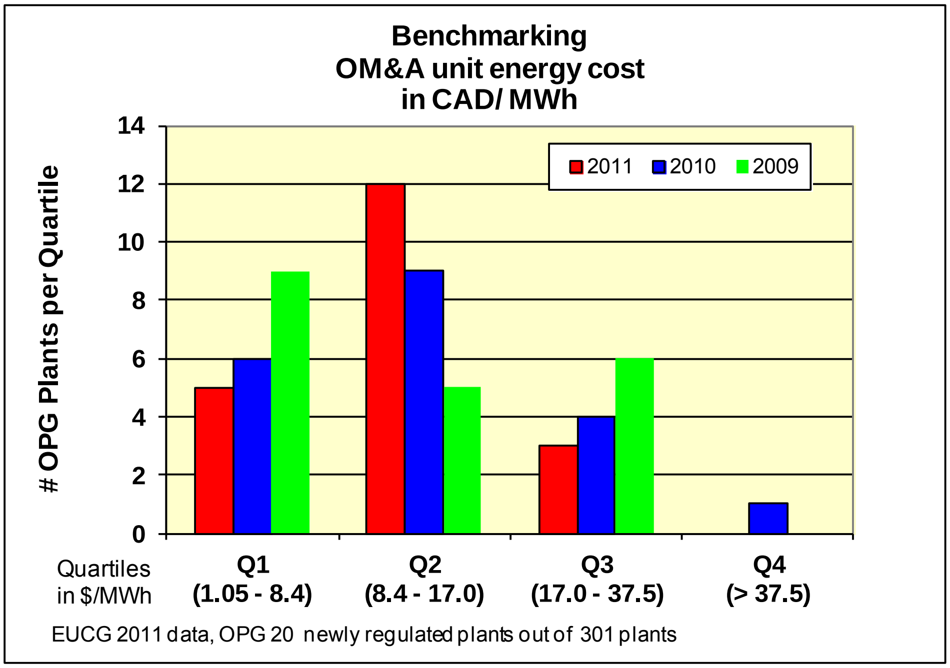


Notes:
99 per cent of Energy Production is in Q1/Q2 (3 year avg.)DeCew Falls I is not included in EUCG Cost Benchmarking Program because EUCG requires concurrent cost and reliability data.
DeCew I will be included starting with 2011 data submission.

Chart 5b shows the EUCG quartile ranking for OM&A unit energy costs of the newly regulated facilities. The newly regulated stations have also been generally better than the EUCG average benchmarks. Over the three year period, an average of 87 per cent of the energy production has ranked in the top two quartiles.

Chart 5b

EUCG Unit Energy Cost Benchmarking Results – Newly Regulated



Note: 87% of Energy Production is in Q1/Q2 (3 year avg.)

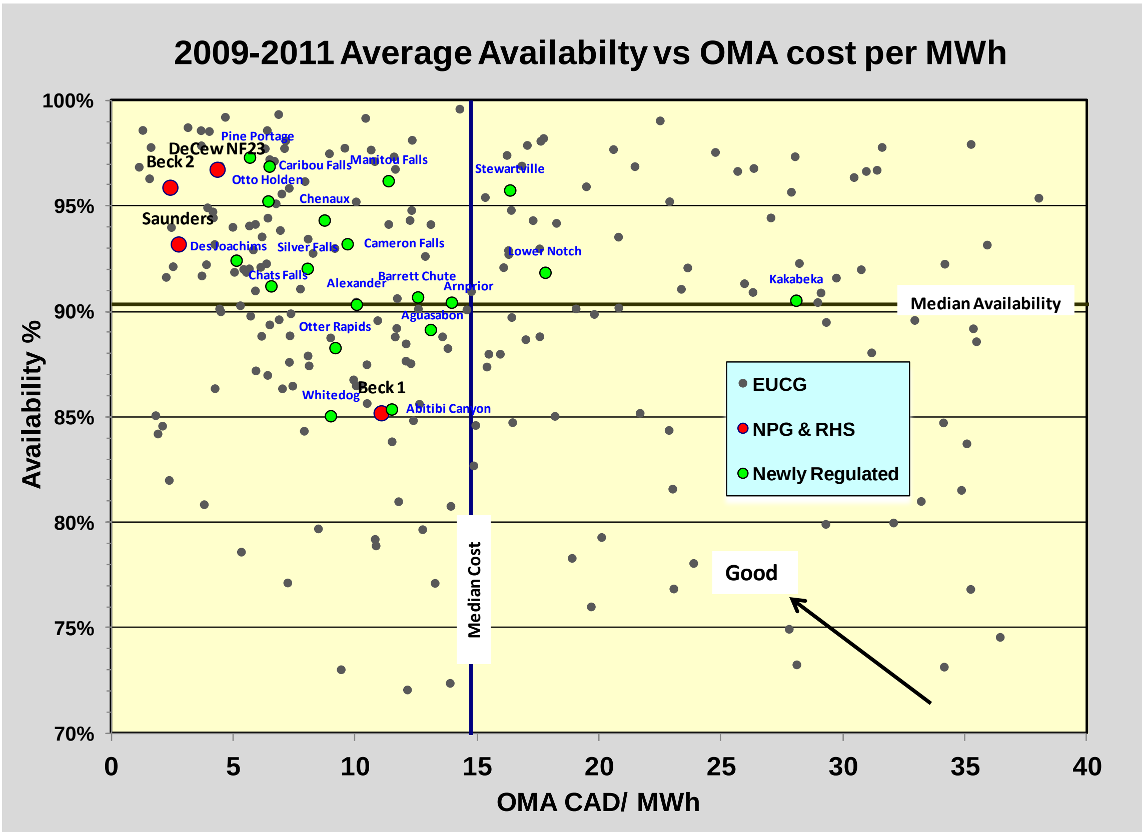
OM&A costs for OPG's regulated hydroelectric facilities are a function of their age, condition and specific circumstances relative to their peer group. Reliable operation is achieved by effective maintenance, but this tends to place upward pressure on OM&A costs. Benchmarking results are also affected by external factors such as water conditions. Based on OM&A unit energy cost benchmarks, OPG's regulated hydroelectric facilities are cost competitive, and have very good reliability, safety and environmental performance.

5.2.3 Combined Availability and Cost Benchmarking

Chart 6 compares OPG's large regulated plants to other facilities based on the combination of EUCG availability and OM&A unit energy cost benchmarks. Desired performance for a generating station is characterized by low unit energy costs with a low EFOR and high availability (i.e. upper left quadrant in the chart). As shown in Chart 6, a significant portion of OPG's large, regulated hydroelectric stations are in the upper left quadrant, with above average availability and below average OM&A costs.

Chart 6

OPG Availability and OM&A Unit Energy Costs



5.3 Safety (All Injury Rate)

OPG spends a significant amount of time and effort on training and awareness to ensure the safety of its employees. Safety performance is benchmarked through the CEA. The CEA collects safety performance data annually from its members who report their injury statistics based on the *CEA Standard for Recording and Measuring Occupational Injury Experience A-2*. The CEA now collects safety performance data from its members broken down into generation type (i.e., nuclear, fossil and hydroelectric).

In 2012, OPG's hydroelectric plant groups' combined AIR was 1.40 (number of medical treatment injuries per 200,000 hours worked), which ranks in the third quartile in CEA benchmarking. On the other hand, the ASR was zero in 2012 (number of days lost due to injuries per 200,000 hours worked), which ranks in the first quartile in CEA benchmarking.

APPENDIX A

DESCRIPTION OF HYDRO THERMAL OPERATIONS BUSINESS PLANNING PROCESS

The Hydro Thermal Operations ("HTO") business planning process begins in early May of each year with internal reviews of the current planning framework, the confirmation and updating of business objectives and priorities, a review of business planning instructions from Finance, a review of the status of operational and performance plans and related capital and OM&A expenditures, a review of benchmarking "best practices" and comparisons, and the identification of emerging issues. Out of this process, strategic and performance objectives and guidelines for HTO are determined, prioritized and finalized.

OM&A and capital guidelines are established for each hydroelectric plant group, thermal plant and HTO central office group in May/June. A three-year time horizon for business planning (2013 - 2015) was used to focus efforts on near-term efficiency gains.

A business planning meeting is held at the end of May with production support management and finance stakeholders from each thermal plant, hydroelectric plant group, and central office groups, and certain corporate groups. The key business planning issues are also discussed at the monthly Hydro Thermal Operations Management Team meetings.

A preliminary HTO Business Plan is provided to the Senior Vice President ("SVP") HTO for review in late August. Redirection is provided to specific groups as required. A formal review meeting is subsequently held at each plant group location with the SVP - HTO and members of the HTO Management Team. The preliminary HTO Business Plan is then modified as required and submitted for review to the President and Chief Executive Officer ("CEO"), and the Chief Financial Officer ("CFO"). Changes are made per the direction of the CEO (if required) prior to its final submission to the OPG Board of Directors, as discussed at Ex A2-2-1.

The key approaches used to identify and prioritize investment and base work program requirements in support of regulated hydroelectric's objectives are described below.

Portfolio Approach to Investment Management

Hydro Thermal Operations uses a structured portfolio approach to identify and prioritize projects for its investment program. Annual engineering reviews and plant condition assessments (conducted on a cycle of approximately seven to ten years) are performed to determine short-term and long-term expenditure requirements to sustain or improve each facility, and ensure continued safe operation. These may be followed by the preparation of a facility life cycle plan. This planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility, and direct limited corporate funds at the facilities that can best maintain or enhance the value of the HTO business and OPG. The cornerstone of this approach is that safety, environmental, and other regulatory programs are of the highest priority. Chart 1 below shows the regulated generating stations by portfolio asset class along with their long-term availability and reliability targets.

Chart 1

Availability and EFOR Targets by Portfolio Asset Class (%)

Asset Class	Regulated Stations				Availability Factor	Equivalent Forced Outage Rate (EFOR)
Flagship	SAB I	SAB II	R.H. Saunders	Des Joachims	**94%**	**1.0%**
Workhorse	DeCew NF23 Pine Portage Silver Falls Abitibi Canyon	SAB PGS Lower Notch Caribou Falls Aguasabon	Otto Holden Chenaux Stewartville	Otter Rapids Mountain Chute Whitedog	**92.5%**	**2.5%**
Middle of the Pack	DeCew ND1 Cameron Falls	Chats Falls Arnprior	Alexander Barrett Chute	Manitou Falls Kakabeka Falls	**91%**	**4.5%**
Small Plants	Big Chute Big Eddy Frankford Auburn Hanna Chute South Falls	Ragged Rapids Sidney Crystal Falls Trethewey Falls Sills Island Lakefield	Matabitchuan Meyersberg Indian Chute Hagues Reach Merrickville	Ranney Falls Seymour Eugenia High Falls Stinson	**85% to 90%**	**5.0%**
Contenders (Small Plants)	Calabogie McVittie	Bingham Chute Nipissing	Elliott Chute	Coniston	**85%**	**7%**

<u>Streamlined Reliability Centred Maintenance Process</u>

Hydro Thermal Operations uses a process known as streamlined reliability centred maintenance to optimize the preventive maintenance program at its facilities. The streamlined reliability centred maintenance process provides a consistent method of identifying, scheduling and executing maintenance activities. The concept of streamlined reliability centred maintenance dictates that the type and frequency of preventive maintenance applied to an individual component is determined based on the nature and consequences of failure (i.e., balance of cost versus risk). By focusing maintenance and associated support resources appropriately, HTO has been able to accomplish more of its base work program (including additional regulatory requirements), while minimizing the need for additional resources.

APPENDIX B

DESCRIPTION OF HYDROELECTRIC KEY PERFORMANCE TARGETS

Availability

Availability is a measure of the reliability of a generating unit represented by the percentage of time the unit is capable of providing service, whether or not it is actually in-service, relative to the total hours for the period in question (typically 8,760 hours in a year).

Equivalent Forced Outage Rate

Equivalent Forced Outage Rate ("EFOR") is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out-of-service, including equivalent forced deratings, compared to the sum of the forced outages and deratings plus the of amount of time the generating unit operates.

OM&A Unit Energy Cost

OM&A unit energy cost measures the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expense, including allocated central support costs, divided by electricity generation. The gross revenue charge ("GRC") is excluded from this calculation because it is determined by provincial regulation and therefore not within the direct control of OPG.

Safety – All Injury Rate

Starting in 2012, in order to improve the focus on employee safety, OPG and the Hydro Thermal Operations Business Unit changed its key safety performance measure to the broader All Injury Rate ("AIR"), in place of the Accident Severity Rate ("ASR"). All Injury Rate is defined as the number of medical treatment injuries reported on the job divided by 200,000 hours worked, whereas the ASR is defined as the number of days lost by employees injured on the job divided by 200,000 hours worked. Both measures are used by other electric utilities and are benchmarked by the Canadian Electrical Association ("CEA").

Environmental Performance

Hydro Thermal Operations uses an environmental performance index to measure the environmental performance of the regulated facilities. The environmental performance index consists of four main categories:

- Spills
- Regulatory compliance (e.g., regulatory infractions)
- Greenhouse and Acid Gas Emissions
- Other Environmental initiatives (e.g. support of Corporate EMS, compliance cost management, work on Endangered Species Act)

LIST OF ATTACHMENTS

Attachment 1: Hydro Thermal Operations 2013 - 2015 Business Plan

Note: Attachment 1 is marked “Confidential” because the original document contains confidential information. The redacted version provided as pre-filed evidence is not confidential.

Filed: 2013-09-27
EB-2013-0321
Ex. F1-1-1
Attachment 1

Hydro Thermal Operations 2013-15 Business Plan

May 16, 2013

Frank Chiarotto, SVP Hydro Thermal Operations

ONTARIO POWER GENERATION

Hydro Thermal Operations Strategies & Key Deliverables

1. **Operate and Maintain Hydro & Thermal Plants with Focus on Sustaining & Regulatory Work**

- Safe and reliable plant operations through prudent maintenance and investment strategy with significant deferral/reductions of value enhancing and low risk work. Utilize a risk-based approach (ie, Plant Condition/Engineering Risk Assessments) for determining investment priorities
- Continue to strengthen and develop relationships with stakeholders to sustain continued operations at existing HTO facilities and [redacted]
- Maintain/improve excellent safety, environmental and reliability performance. Continue prudent investments and improvements in Dam and Public Safety program
- [redacted] commitments are met and value to OPG is maximized

2. **Transform Hydro Thermal Operations into a Low Cost, Agile and Variable Business Model**

- Complete implementation of BTS centre-led model, reductions, and initiatives
- Transition the business to a more flexible and cost variable model
- [redacted]
- Prepare OEB 2014/15 Cost of Service filing and Niagara Tunnel Prudency Review. Prepare for and implement Incentive Regulation as per OEB appropriate schedule
- Implement/operationalize Information Management Transformation project (SAP to Passport/Asset Suite)

ONTARIO POWER GENERATION

Hydro Thermal Operations Strategies & Key Deliverables (Cont'd)

3. Optimize Costs & Project Timing - Move Hydro Value Enhancing/Capacity Projects to Post 2016 Period and [redacted]

- Total plan over plan OM&A cost reduction of [redacted] ([redacted] in 2012, [redacted] in 2013 and [redacted] in 2014) achieved through:
  - [redacted] and deferral of lowest risk major overhaul and civil maintenance projects in the Hydro fleet ([redacted])
  - Absorption of labour escalation ([redacted]) through productivity improvements and work program reductions and optimization
  - Reductions in non-base labour and other costs of approximately [redacted] per year (eg, Society PSA reductions associated with reduced project portfolio, overtime savings on outages, non-essential travel reductions)
- Total plan over plan capital cost reduction of [redacted] during 2012 to 2014 period. HTO will execute the planned capital project portfolio for existing assets on budget and schedule (average [redacted] per year)

4. Grow the Business

- Provide Project Management support to ensure projects are safely delivered on time, budget and scope
- Support Corporate Business Development in new generation opportunities ([redacted] Ranney Falls, [redacted]
- [redacted]

OPG CONFIDENTIAL

ONTARIO POWER GENERATION

Planning Assumptions (2013 to 2015)

Hydro

- Focus on regulatory and sustaining work during planning period. Value enhancing projects (runner upgrades) deferred to post 2015 period
- Hydro major unit refurbishment and outage program aligned with Darlington refurbishment timing. Non-system impactive outages deferred to post 2016 period
- PGS Reservoir rehabilitation and full station outage deferred from 2014 to 2016/17 to mitigate Surplus Baseload Generation (SBG) spill losses
- Niagara Tunnel in-service mid-2013 (6 months early) and cost of $1.5B versus budget of $1.6B
- [redacted]

Thermal

- [redacted]
- [redacted]
- [redacted]
- [redacted]

General

- HTO staff dedicated to the implementation of the IMT project funded by BAS (Capital – Execution Phase)
- Development projects entering Execution Phase in 2013 are included in the HTO Business Plan. Hydro Development/repowering projects in definition and concept phase, [redacted], are included in the Corporate Business Development plan
- Aboriginal past grievance provision/contingency will be funded by Stakeholder Relations ($5 M per yr)

Filed: 2013-09-27
EB-2013-0321
Ex. F1-1-1
Attachment 1

Hydro Thermal Operations Performance Summary

	2012 Actual	2013	2014	2015
PRODUCTION				
Capacity (MW)	[redacted]	[redacted]	[redacted]	[redacted]
Hydro	6,996	6,996	7,063	7,433
Thermal	[redacted]	[redacted]	[redacted]	[redacted]
Energy (TWh)	[redacted]	[redacted]	[redacted]	[redacted]
Hydro	[redacted]	[redacted]	[redacted]	[redacted]
Thermal	[redacted]	[redacted]	[redacted]	[redacted]
Hydro Availability (%)	91.2	91.6	92.6	91.2
Thermal Start Guarantee (%)	[redacted]	[redacted]	[redacted]	[redacted]
EFOR (OP) (%)	[redacted]	[redacted]	[redacted]	[redacted]
RESOURCES				
Total OM&A ($M)	[redacted]	[redacted]	[redacted]	[redacted]
Base OM&A ($M)	[redacted]	[redacted]	[redacted]	[redacted]
Project OM&A ($M)	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital ($M)	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Niagara Tunnel ($M)	231	184	0	0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Regular Staff	[redacted]	[redacted]	[redacted]	[redacted]

ONTARIO POWER GENERATION

Hydro Thermal Operations OM&A Plan over Plan

OM&A ($M)	2012 Actual	2013	2014	2015
Approved 2012 OM&A Business Plan	[redacted]	[redacted]		
Business Transformation - Phase 1 Transfers to Corporate Groups				
Corporate Labour Escalation Challenge (PWU, Society, & Management)				
Labour Rate & Burden Changes (2013-2015)				
Revised 2013 OM&A Guideline				
[redacted]				
Non-Standard Projects Changes				
Schedule Change (deferred, cancelled or advanced)				
Scope Change				
Cost Change (escalation and revised estimates)				
New Project (from Plant Conditon Assessments)				
Other				
2013 OM&A Submission				
2013 OM&A Submission versus Revised 2013 OM&A Guideline				

Hydro Thermal Operations Capital Plan over Plan

CAPITAL ($M)	2012 Actual	2013	2014	2015
Approved 2012 Capital Business Plan	[redacted]	[redacted]		
Business Transformation - Phase 1 Transfers to Corporate Groups				
[redacted]				
Revised 2012 Capital Business Plan				
Operations Projects Changes				
[redacted]				
Schedule Change (deferred, cancelled or advanced)				
Scope Changes				
Cost Changes (escalation and revised estimates)				
New Project (from Plant Condition Assessment)				
Other				
Destiny Project Changes				
Niagara Tunnel Project	8	5	-32	0
[redacted]	[redacted]	[redacted]		
Total 2013 Capital Submission				
2013 Capital Submission versus Revised 2012 Capital BP				

ONTARIO POWER GENERATION

Hydro Development / Thermal Repowering Projects

Base Case	Capacity	LUEC	2012 LTD	2013	2014	2015	2016	2017	Future costs	Total
	MW	cents/kWh	$M	$M	$M	$M	$M	$M	$M	$M
Projects In Execution (HTO)										
Niagara Tunnel Project	n/a	6.8	1,316	184						1,500
[redacted]										
Total HTO	[redacted]									

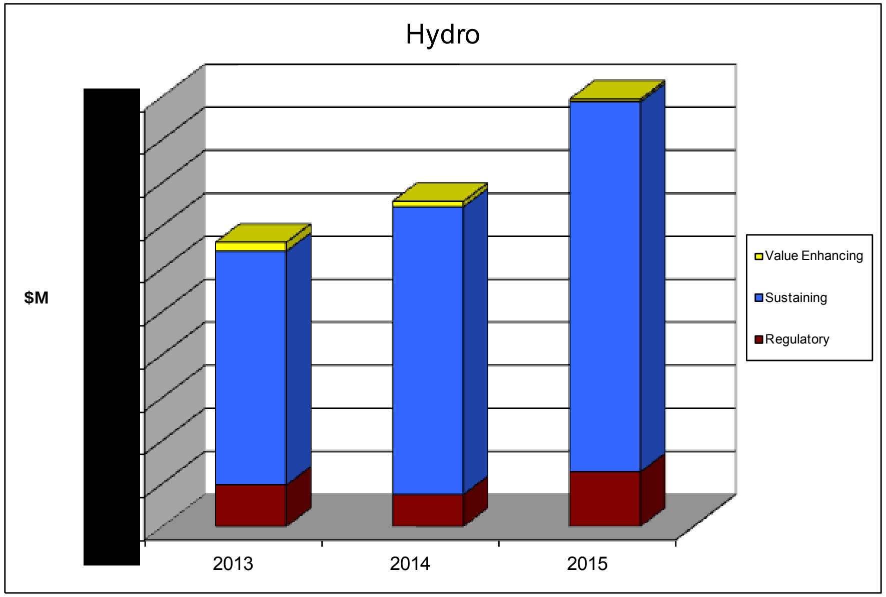
Base Case	Capacity	LUEC	2012 LTD	2013	2014	2015	2016	2017	2018	Total
	MW	cents/kWh	$M	$M	$M	$M	$M	$M	$M	$M
Projects In Definition Phase (CBD)										
[redacted]										
Ranney Falls	9	10 to 12	1	3	19	19	1			42
SAB PGS Reservoir Rehabilitation	n/a	n/a	7	3	0	0	176	176		362
Total CBD (Definition Phase)	[redacted]									

* Projects in Definition Phase are included and funded in the Corporate Business Development (CBD) Business Plan

- Projects in execution phase included in the HTO Business Plan. Projects in Definition Phase (except Thunder Bay GS) included and funded in the Corporate Business Development (CBD) Business Plan
- Projects in Definition Phase, including [redacted], Ranney Falls and SAB PGS Reservoir Rehabilitation, will be transferred to HTO after execution phase releases are approved
- [redacted]
- High Planning Scenario projects including [redacted] and Lake Gibson are included in the Corporate Business Development Business Plan

OPG CONFIDENTIAL

Project Expenditures on Existing Assets



[redacted]

- ➢ Continued re-investment for the long term safety and sustainment of the existing assets includes project expenditures averaging [redacted] per year (Capital ([redacted]) & OM&A ([redacted]))
- ➢ Determination of investment levels and priorities are based on Plant Condition/Engineering Risk Assessments and inspections/testing, and consider station/fleet age , type of equipment, station role (peaking vs base), reliability targets, contract commitments [redacted]), and business objectives and risks
- ➢ Hydro re-investment levels of ~1% of the "replacement cost" (excluding new facilities) are based on good practice
- ➢ Major Hydro investments during planning period include:
  - replacement of ageing "power train components" such as turbines, generators, transformers
  - repairs, rehabilitation or replacement of ageing civil structures including powerhouses, penstocks, dams, sluiceways and bridges
  - replacement or refurbishment of sluicegates & stoplogs (regulatory/safety) and headgates
  - replacement of control equipment (automation) to improve efficiency and accommodate market dispatch requirements
- ➢ [redacted]

Hydro Thermal Operations Existing Fleet Project Portfolio Plan over Plan

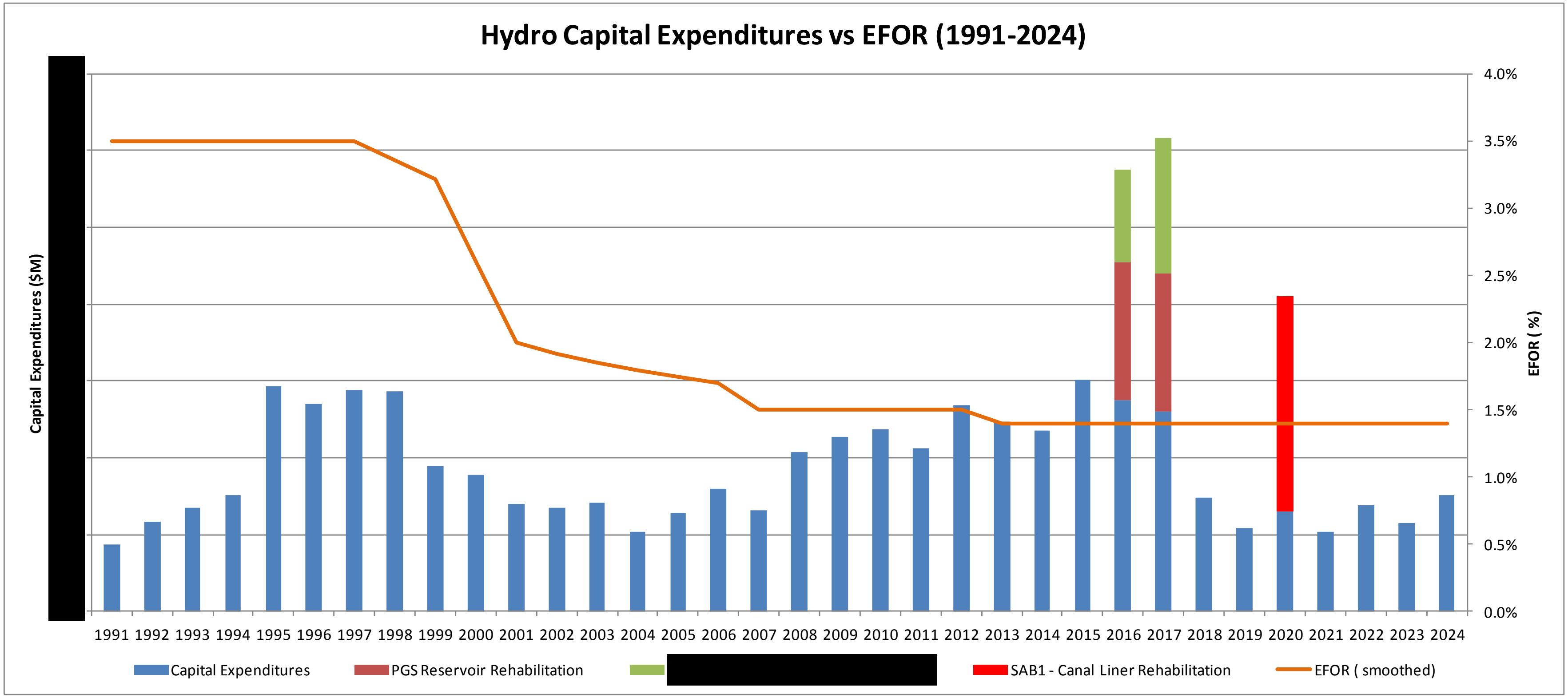
	2012	2013	2014
2012-2014 BP			
Hydro Capital and OM&A Project Investments (M$)	[redacted]		
Thermal Capital and OM&A Project Investments (M$)			
2012-2014 BP Total Hydro + Thermal Investment			
2013-2015 BP			
Hydro Capital and OM&A Project Investments (M$)	[redacted]		
Thermal Capital and OM&A Project Investments (M$)			
2013-2015 BP Total Hydro + Thermal Investment			
Total HTO Project Portfolio Plan Over Plan Change	[redacted]		

- In the 2012-2014 period, the HTO operations project portfolio (Capital and OM&A Non Standard projects) [redacted] by a total of [redacted] and [redacted] of Hydro value-enhancing projects

OPG CONFIDENTIAL

ONTARIO POWER GENERATION

Historical Hydro Capital vs EFOR



- From 1990 to 2003, large Hydro stations primarily built before 1958 were rehabilitated (eg, Saunders, SAB 2, Otto Holden, and Chenaux)
- From 2006 to 2020, remaining large stations have been, or will be rehabilitated (eg, Abitibi Canyon, Des Joachims, Decew Falls, Stewartville, Mountain Chute)
- In addition, large civil projects (PGS Reservoir liner rehabilitation, [redacted] and SAB 1 canal rehabilitation) are planned
- The investment program, along with the Leading Edge Maintenance Program, has resulted in significant reliability (EFOR) improvements.

Note: Capital Costs in $ of the year

Hydro Thermal Operations Staff Plan & Strategy

[redacted]

- HTO expected to achieve overall BTS end state staff numbers in 2015
- Overall HTO attrition rates favourable, however, mismatches in retirement vs ongoing skill requirements will necessitate replacements in critical areas (eg operators)
- [redacted]

ONTARIO POWER GENERATION

[redacted]

OPG CONFIDENTIAL

Key Business Risks

		Risk Ranking
1	[redacted]	
2		
3	Aboriginal: Increasing complexity of role and potential cost increases for unsettled past grievances	Medium
4	Uncertainty of full cost recovery for Hydro Regulated Assets and Niagara Tunnel Project	Medium
5	Implementation costs of new Provincial Dam Safety technical guidelines. Overall cost risk has been reduced compared to previously proposed MNR guidelines last year. Site specific impacts need to be assessed and could result in additional capital costs not included in plan ($100M to $400M)	Medium
6	Environmental risks associated with Ontario Endangered Species Act and Federal Species at Risk Act (compliance may require physical improvement costs and/or impacts on production/revenue) ($100M)	Medium
7	Increased cost and delayed completion of destiny projects (NTP – Low; [redacted])	Low
8	Increased costs due to new Heritage Act ($30M)	Low
9	New requirements for Permits to Take Water	Low
10	Uncertainty with future reliability of Hydro and Thermal plants associated with changing operating modes (eg, more stops and starts and gate operations due to SBG mitigation and wind integration)	Low
11	Structural and other operational risks associated with AAR induced concrete growth at Otto Holden and Saunders, ageing penstocks, and ageing bridges in Niagara	Low
12	Underestimating Future Cost Escalation for Major Equipment and Civil Construction	Low
13	Uncertainty with successful implementation of IMT Project and adequacy of Passport/Asset Suite	Low

OPG CONFIDENTIAL

ONTARIO POWER GENERATION

Looking To The Future - Opportunities

The following opportunities and strategies will be reviewed by HTO during the 2013-2015 BP Period

1. Transition the business to a more cost variable model
   - Optimization of Hydro overhaul and major maintenance resourcing strategy
   - [redacted]
   -

2. [redacted]

3.

4.

5. Investment Strategy aligned with regulated, [redacted] requirements

Appendices

Hydro Asset Profile

STATIONS PROFILE

NO. OF STATIONS	65
AVERAGE ENERGY	34.3 TWh/yr
CAPACITY	6996 MW
AVERAGE AGE	71 yrs
NO. OF GENERATING UNITS	234
SMALLEST / LARGEST UNIT	1 MW / 137 MW
NO. OF DAMS	232
BOOK VALUE OF ASSETS	~$7.1 B

PEOPLE / WORK CENTRES / LAND

PLANT GROUPS	5
WORK CENTRES	22
CONTROL CENTRES (includes International Control Dam Control Centre)	7
TOTAL STAFF (PG only)	~980 (2012 Plan)
OPERATORS	~105
NO. OF RIVER SYSTEMS	24
HYDRO OWNED LAND	~17,000 hectares
LEASED LAND (flooded)	~800, 000 hectares

OPG CONFIDENTIAL

ONTARIO POWER GENERATION

Thermal Asset Profile

[redacted]

HTO Reliability Performance

	2012 Budget	2012 YE Actuals	2013	2014	2015
Hydro					
Availability	91.2%	91.2%	91.6%	92.6%	91.2%
Scheduled Outage Factor	7.4%	7.4%	7.3%	6.3%	7.7%
EFOR	1.4%	2.0%	1.4%	1.4%	1.4%
Spill Losses (Forced + Planned Outages) (GWh)	220	198	366	384	368
Thermal					
Start Guarantee	[redacted]				
CAWN					
Maintenance Outage Factor (%)					
EFOR(OP)					

ONTARIO POWER GENERATION

Runner Replacement /Upgrade Program

2013-2015 BP Runner Upgrades	Completed 1992 to 2011	2012 Actual	2013	2014	2015	2013-2015 BP Total	2016	2017	2018	2019	2020	Total (2013 to 2020)
CAPACITY (MW)	464	[redacted]										
ENERGY (GWh)	885											
TOTAL CAPITAL COST (M$)	243											
OM&A COST (M$)	23											

- All runner replacements that were in the plan, solely to enhance value (not sustaining), have been deferred to the 2016 to 2020 period (eg Otter Rapids)
- During the Business Plan period, HTO capacity and energy are expected to [redacted] respectively, as a result of runner upgrades. This is a [redacted] compared to last year's plan
- From 1992 to 2012, HTO will have realized an increase in capacity of 464 MW and 885 GWh, as a result of the runner upgrade program

ONTARIO POWER GENERATION

Numbers may not add due to rounding.

Table 1
Operating Costs Summary - Previously Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A**[1]	59.4	50.1	60.2	71.9	74.6	68.6
2	**Project OM&A**	5.4	6.6	13.6	13.0	13.5	17.9
3	**Allocation of Corporate Costs**	22.4	22.0	24.5	29.7	29.8	26.9
4	**Allocation of Centrally Held Costs**	19.6	15.9	19.6	25.1	26.1	26.0
5	**Asset Service Fee**	2.1	1.6	1.8	1.7	1.5	1.7
6	**Total OM&A**	108.8	96.3	119.7	141.3	145.5	141.1
7	**Gross Revenue Charge**	252.2	259.4	244.5	243.5	253.3	269.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization**	63.5	65.6	70.0	79.0	82.1	81.9
9	**Income Tax**	29.9	33.4	32.3	(0.7)	48.5	61.5
10	**Capital Tax**	2.8	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.1	0.2	0.2	0.3	0.3	0.3
12	**Total Operating Costs**	457.4	454.9	466.6	463.5	529.5	554.4

Notes:
1 2011 Actual Base OM&A cost includes an extraordinary credit of $19.0M in Niagara Plant Group related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

Table 2
Operating Costs Summary - Newly Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A[1]**	100.0	106.0	102.9	113.2	113.4	113.7
2	**Project OM&A**	39.8	21.6	20.3	16.0	24.5	32.1
3	**Allocation of Corporate Costs**	31.4	32.3	36.6	38.8	42.1	39.6
4	**Allocation of Centrally Held Costs**	19.0	25.1	33.1	47.2	49.6	48.7
5	**Asset Service Fee**	3.6	3.4	3.3	3.1	2.9	3.0
6	**Total OM&A**	193.8	188.4	196.2	218.2	232.5	237.2
7	**Gross Revenue Charge**	54.9	67.7	65.6	75.6	75.6	77.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization**	58.3	58.0	58.6	61.4	62.2	63.1
9	**Income Tax**	N/A	N/A	N/A	N/A	31.4	43.2
10	**Capital Tax**	N/A	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.2	0.2	0.2	0.2	0.2	0.2
12	**Total Operating Costs**	307.2	314.3	320.6	355.5	401.9	421.2

Notes:
1 2011 Actual Base OM&A cost includes an extraordinary credit of $19.0M in Niagara Plant Group related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

BASE OM&A - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the regulated hydroelectric base OM&A costs for the historical period, bridge year and test period.

2.0 OVERVIEW

This evidence supports the approval sought for the proposed regulated hydroelectric base OM&A for the test period. The regulated hydroelectric base OM&A expenses for 2010 - 2015 are provided in Ex. F1-2-1 Table 1. The test period base OM&A expenses for the Niagara Plant Group and R.H. Saunders GS are $143.2M ($74.6M in 2014 and $68.6M in 2015), and for the newly regulated faclilites $227.1M ($113.4M in 2014 and $113.7M in 2015).

Base OM&A funds routine, day-to-day operations and maintenance-related activities in support of the production of electricity from OPG's regulated hydroelectric generating stations, along with associated administration and Hydro Thermal Operations Central Support Group costs. As shown in Ex. F1-2-1 Table 4, the staff complement (FTEs) associated with the regulated hydroelectric facilities has remained relatively stable over the 2010 - 2015 period. Therefore, the year-over-year changes in base OM&A costs are mostly related to: labour rate changes, extraordinary items described in Section 3.0 below, the Business Transformation reorganization described in Ex. A4-1-1 and A1-4-2 section 4.1, and some additional maintenance planned in certain plant groups. Details of the year-over-year variances in base OM&A expenditures for the historical, bridge and test years are discussed in Exhibit F1-2-2.

Detailed descriptions of the activities included in base OM&A costs are provided below in sections 3.0 and 3.1. Section 3.2 describes the Ottawa - St. Lawrence Plant Group common support costs and the methodology for allocating these between R.H. Saunders GS and the newly regulated stations. This level of allocation exists only within the Ottawa - St. Lawrence Plant Group since the headquarters departments provide support for both R.H. Saunders and the balance of stations that are part of the newly regulated segment. Section 3.3

describes the methodology for allocating base OM&A costs between OPA contracted stations and the newly regulated stations. This level of allocation exists only within the Central Hydro, Northeast, and Northwest Plant Groups that manage OPA contracted stations. Sections 3.4 and 3.5 describe the Hydro Thermal Central Support Groups and the methodology for allocating costs to the regulated hydroelectric stations.

3.0 REGULATED HYDROELECTRIC BASE OM&A

3.1.1 Base OM&A

Base OM&A expenditures for OPG's regulated hydroelectric facilities are attributed on a work program basis, consistent with how costs are incurred. The OM&A budgets are established through the annual business planning process (see Ex. A2-2-1 and Ex. F1-1-1). Base OM&A budgets in each of the plant groups are categorized in the following general work programs: operations, maintenance, and administration support.

Operations costs include all direct costs to operate the generating facilities for the purpose of generating electricity or producing other related products (e.g., ancillary services required by the electricity system). These costs include costs for control room operators, water management activities including dam operations, dam safety surveillance inspections, waterway patrol, water flow monitoring/snow surveys, ice breaking, and log operations. These costs also include OPG's portion of all joint works operations costs, for example with the New York Power Authority ("NYPA") pursuant to Joint Works Agreements.

Maintenance includes all costs associated with the direct maintenance of the facilities to ensure their normal, safe, and environmentally sound operation. Maintenance plans are established in a maintenance management system. The plans are used to prioritize work execution and used to support budget requirements. As indicated in Ex. F1-1-1 Appendix A, investment in hydroelectric facilities (including base OM&A funding) is determined using a structured portfolio approach, and streamlined reliability centered maintenance principles. The maintenance work program also includes OPG's portion of the maintenance costs for joint works (e.g. NYPA).

Administration costs within the plant groups include all common support and other costs incurred for the production facilities that are not directly related to the production of electricity. In addition to the costs incurred within the plant groups, certain other costs incurred to support the regulated hydroelectric facilities are provided on a centralized basis. The Hydro Thermal Operations (HTO) Central Support Groups' costs include functions and activities not provided within the plant groups such as specialized Engineering, Strategy and Business Support, Dam Safety and Emergency Preparedness, and Hydro Thermal Project Execution.

3.1.2 Plant Group Staffing and Overtime

Plant Group staffing levels related to the regulated facilities are shown in F1-2-1 Table 4 and include the total of regular and non-regular staff deployed for base OM&A, project OM&A, and capital projects. Plant Group staffing levels also include an allocation of staff (FTEs) between unregulated and regulated stations, and an allocation of HTO Central Support and Ottawa – St. Lawrence Plant headquarters groups to the regulated stations. Staff (FTEs) were allocated based on the percentage of total base OM&A costs allocated to the regulated hydroelectric stations.

Incremental short-term labour resources utilized by hydroelectric plant groups include overtime and temporary staff (i.e. non-regular staff). These resources are used for peak work requirements (e.g. outages, responding to weather events, etc.), seasonal work, or to complete necessary work impacted by short-term staff absences or vacancies.

Plant groups have been directed to reduce overtime wherever possible. As a result, hydroelectric overtime usage has been reduced from 11 per cent of labour cost in 2001 to under 6 per cent –for the test period. Hydroelectric plant groups also track overtime usage against approved budgets throughout the year. Almost half of the overtime is used for maintenance activities, approximately a third is used for project work (capital and OM&A), about 15 per cent is used for operating activities, and only about 5 per cent is used in administration. Budgets for temporary employees are mainly for seasonal workers (e.g. summer students) and other forecast requirements. However, the actual utilization of temporary staff is usually higher than budget since temporary staff are often hired for unforeseen work or to backfill for vacant regular staff positions until they are filled (See Appendix 2K, Ex. F4-3-1).

3.1.3 OM&A Costs by Resource

In Ex. F1-2-1 Tables 2 and 3, OM&A costs are presented by resource type. Direct plant group labour accounts for approximately 66% of total base OM&A costs in the test period. Labour costs include both regular and non-regular OPG employees, and their related overtime. The remainder of total base OM&A is composed of allocated HTO support group costs (13%), purchased services (10%), materials (6%), and other costs (5%).

3.1.4 Extraordinary Items

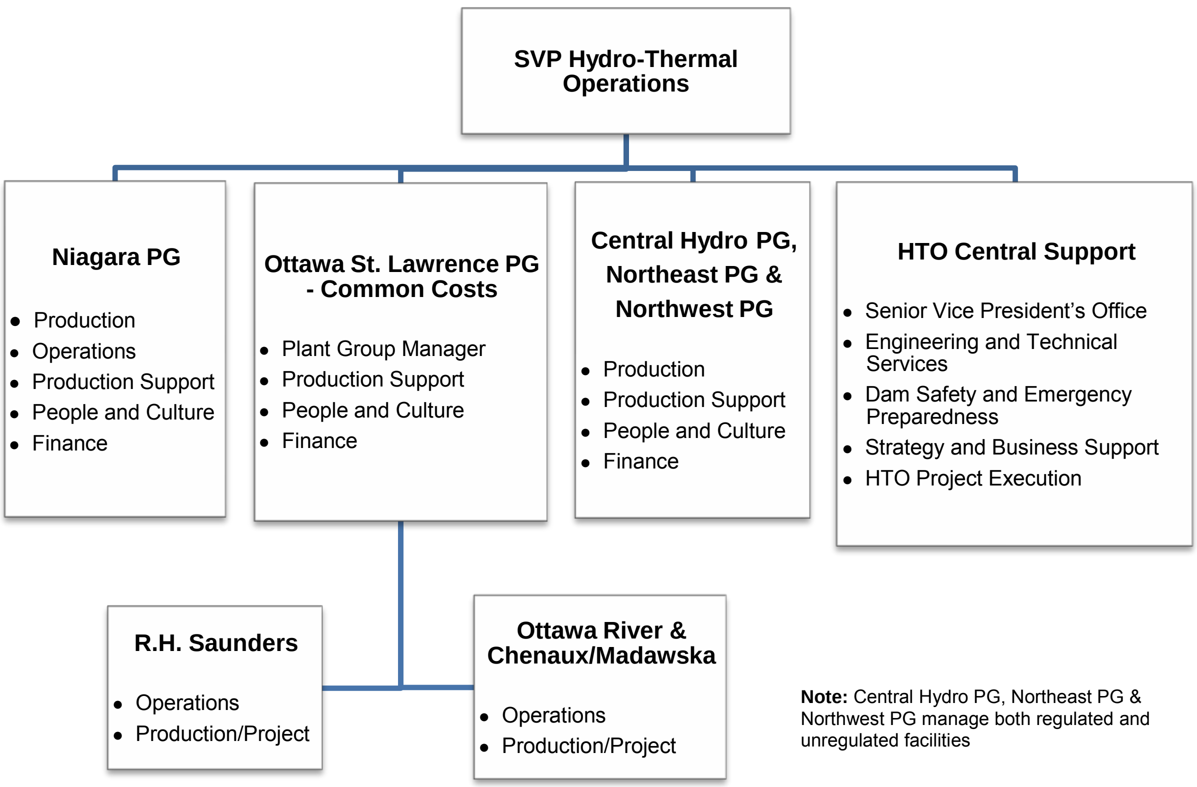
Niagara Bridge Divestitures

Included with the Niagara Plant Group's administrative costs is a program to divest certain bridges in the Niagara Region owned by OPG. In 2009, OPG reached an agreement with the City of Thorold to transfer to the city the Laura Secord Bridge, and reached a similar agreement in 2011 for the Niagara Falls Road Bridge. These agreements successfully relieved OPG of all future liabilities associated with these bridges. Negotiations are ongoing with the Niagara Region to divest two more bridges, planned for 2013 - 2014.

Lake Gibson Provision

In addition to bridge divestitures, the Niagara Plant Group's actual administrative costs in 2011 include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS). A long-term liability provision was established by OPG, prior to April, 2005, for the clean-up of contaminated sediments in Lake Gibson. Since that time work has been done by OPG in consultation with the Ministry of Environment (MOE) to assess the risk associated with the contamination and related cleanup. This work culminated in two assessment reports completed and approved by the MOE in December 2009 and February 2012. The reports explain that the contaminated sediments are not considered threats to drinking water drawn from Lake Gibson. Therefore, no remediation of the Lake Gibson sediment contamination is anticipated. Correspondingly, the liability provision was reversed resulting in an extraordinary credit of $19M in 2011.

Hydroelectric Organization



3.2 Plant Group Organization Description

OPG's five hydroelectric plant groups have similar organizational structures. Described below, along with the minor differences between plant groups, are the departments that typically support the Plant Group Manager. These departments include:

- Production Department
- Production Support Department
- People and Culture Department (Human Resources/ Public Affairs/ Health & Safety)
- Finance Department

The methodology for allocating plant group costs are described in Sections 3.3 and 3.4.

3.2.1 Production Department

The Production Department's function in each of the plant groups is to control and maintain the generation assets to produce electrical capacity, energy, and energy-related products and services at targeted performance levels. This includes plant maintenance, shop services, and materials stores. The Production Department is also accountable for the operation of the generating stations and all associated water conveyance structures in accordance with approved plans and applicable policies, contracts (e.g. NYPA Joint Works), and legal requirements.

In the Niagara Plant Group, there are separate Production and Operations departments reporting to the Plant Group Manager. Further, the Ottawa – St. Lawrence Plant Group, due the its size, operates with three Production departments, one each for: R.H. Saunders GS, the Ottawa River, and Chenaux GS / Madawaska River, including the operation of control rooms at R.H. Saunders GS and Chenaux GS. Finally, as previously described in EB-2010-0008, the Ottawa – St. Lawrence production departments are also responsible for the management of projects.

The staff associated with Production functions are funded mostly through plant group base OM&A budgets. There are 106 staff (2013 year-end value) associated with the Production Department and 44 with the Operations Department in the Niagara Plant Group. In the Ottawa-St. Lawrence Plant Group, 68 Production staff are associated with R.H. Saunders GS, 78 staff with the Ottawa River stations, and 109 with Chenaux GS and the Madawaska River stations. In the other plant groups, there are 79 staff associated with the Production Department in the Central Hydro Plant Group, 84 in the Northeast Plant Group, and 109 in the Northwest Plant Group.

3.2.2 Production Support Department

As part of the 2012 Business Transformation reorganization, the Production Support Departments were created mainly from the former Asset and Technical Services Departments and Project Departments in each plant group. The Production Support Department provides specialist expertise in the area of business strategy, planning, programming, asset portfolio management, decision support, business effectiveness, due diligence in environment and managed systems, engineering support, execution of projects, and consolidated site support services. However, the Niagara Plant Group's Production Support Department also includes the site services function of the former Services Department. Further, as described above, the Ottawa – St. Lawrence Plant Group includes project management function within their Production Departments.

The staff associated with these functions are mostly funded through plant group base OM&A budgets. There are 75 staff (2013 year-end value) associated with these functions in the Niagara Plant Group, 28 staff in the Ottawa-St. Lawrence Plant Group, 20 in the Central Hydro Plant Group, 22 in the Northeast Plant Group, and 21 in the Northwest Plant Group.

3.2.3 People and Culture Department

The People and Culture Department within each plant group provides support in the areas of labour relations, vacancy management, health and safety, disability management, compensation and benefits. The staff associated with these functions are part of OPG's People and Culture corporate function and allocated through the cost allocation process described in Ex. F3-1-1. There are six staff (2013 year-end value) associated with these functions in the Niagara Plant Group, five staff in the Ottawa-St. Lawrence Plant Group, four in the Central Hydro Plant Group, four in the Northeast Plant Group, and four in the Northwest Plant Group.

Also reporting to the People and Culture Department Manager are plant group staff that provide support for public affairs, stakeholder relations, community relations services, and other support for the plant group. There are four staff (2013 year-end value) associated with these functions in the Niagara Plant Group, one in the Central Hydro Plant Group, two in the Northeast Plant Group, and three in the Northwest Plant Group. In the Ottawa – St. Lawrence Plant Group starting in 2013, there are 6 staff (2013 year end value) reporting to the Plant Group Manager providing the site business and public relations support.

3.2.4 Finance Department

The Finance Department, is managed by a Site Controller and provides financial management support within each plant group. The department supports business planning, budgeting, financial forecasting, management cost reporting and analysis, review of all business cases, and monitoring adherence to corporate policies with respect to business expenses, project classification, procurement, and internal control. In general, the staff associated with these functions are part of OPG's corporate Finance Group and their costs are allocated through the corporate cost allocation process described in Ex. F3-1-1. However, some plant group funded staff also support these functions in the Central Hydro and Northeast Plant Groups. For the Ottawa-St. Lawrence Plant Group, as described in section 3.1.3 above, the plant group funded business support staff will be reporting to the Plant Group Manager as of 2013.

There are four staff (2013 year-end value) associated with these functions in the Niagara Plant Group, four staff in the Ottawa-St. Lawrence Plant Group, three in the Central Hydro Plant Group, four in the Northeast Plant Group, and two in the Northwest Plant Group.

3.3 Ottawa - St. Lawrence Plant Group Common Costs

This section describes the Ottawa - St. Lawrence Plant Group common headquarters departments and explains the methodology for allocating their costs to R.H. Saunders GS and balance of the plant group stations that are in the newly regulated segment. The allocation methodology follows the recommendations of R.J. Rudden Associates, Black & Veatch Corporation, and HSG Group Inc as described below in section 3.5.

The Plant Group Manager leads, manages, and supports the provision of common services. Starting in 2013, some staff previously with the People and Culture Department and the Finance Department were included under the Plant Group Manager in a minor reorganization. The services provided by the People and Culture Department and the Finance Department are described above. The total cost of these three groups is allocated to R.H. Saunders based on its proportion of the total budgeted base OM&A within the Ottawa - St. Lawrence Plant Group. Base OM&A is generally linked to the size of the station and its generation and therefore provides a reasonable basis for allocating common services costs as discussed below in section 3.5.

As described above, the Production Support Department provides specialist services (e.g. engineering) within the Ottawa - St. Lawrence Plant Group. R.H. Saunders is resourced to provide some level of asset management and engineering support. As a result support provided from the Production Support Department is modest and estimated at 15 per cent of the total department costs based on management's estimates. Further, up until the end of 2012, R.H. Saunders was resourced to provide its own compliance management (information and records management functions) and, based on management's estimates, none of the compliance management function costs from this department were allocated to R.H. Saunders. During the minor reorganization of headquarters support costs for 2013, it was determined that Production Support would be providing compliance management services to R.H. Saunders GS. Therefore, starting in 2013, compliance management costs are being allocated to R.H. Saunders based on its proportion of the total budgeted base production OM&A within the Ottawa/St.Lawrence Plant Group.

The balance of the headquarters support costs not allocated to R.H. Saunders GS are fully attributable to the newly regulated Ottawa and Madawaska River stations. Approximately 20% of the costs for the common headquarters departments are allocated to R.H. Saunders, and 80% to the newly regulated hydroelectric stations.

3.4 Allocation Methodology for Plant Groups with Newly Regulated and Unregulated Facilities

OPG uses a standardized allocation methodology for plant groups that include newly regulated and unregulated hydroelectric stations. The methodology used to allocate OM&A costs varies depending on the nature of the cost at each specific organizational level. Base maintenance costs are charged directly to the stations. Indirect plant group costs are allocated using the station capacities (i.e., megawatts). HTO Central Support and Corporate costs allocated to the plant groups are further allocated to the station level based on the percentage of the station's contribution to the total OM&A costs (direct and indirect) within the plant group. As required by the corporate allocation methodologies, pension and OPEB costs are allocated using a labour allocator (headcount, FTE). The allocation of costs to the newly regulated hydroelectric stations is consistent with the principles established for other OPG cost allocations.

For 2014 – 2015, using the allocation method described above, approximately 89 per cent of the total Central Hydro Plant Group costs, 50 per cent of the total Northeast Plant Group costs, and 92 per cent of the total Northwest Plant Group costs, have been allocated to the newly regulated stations.

3.5 HTO Central Support Groups Description

Prior to 2012, the Hydroelectric Central Support Groups, providing common or specialized services to all of the hydroelectric plant groups, consisted of the following groups: Engineering, Dam Safety and Emergency Preparedness, First Nations and Metis Relations (formerly Aboriginal Relations), Business Support, Water Resources, Environment, Hydroelectric Development, Hydroelectric Supply Chain, and the Executive Vice President's office.

At the beginning of 2012, as a result of the Business Transformation reorganization, the Hydro and Thermal Business Units were combined into one Hydro Thermal Operations Business Unit (HTO). In addition, to align with the centre-led model as set out in Ex. A4-1-1, the First Nations and Metis Relations (formerly Aboriginal Relations), Water Resources, Environment, Supply Chain and the Business Development section of Hydroelectric Development, were transferred to various corporate groups. The impacts on the OEB approved central support allocations for 2012 are shown in Table 1. In the new Hydro Thermal Operations Business Unit, the Central Support Groups, providing common or specialized services to the Hydro Plant Groups and Thermal stations, consist of :

- Senior Vice President's Office
- Engineering and Technical Services
- Dam Safety and Emergency Preparedness
- Strategy and Business Support

- HTO Project Execution.

Table 1
2012 OEB Approved Central Support Allocations
Restated for the Impact of Business Transformation

Line No.	Hydroelectric Central Support Groups as per EB-2010-0008 F1-2-2 Table 1	2012 OEB Board Approved	Business Transformation Transfers Out of Hydro	HTO Central Support Groups as per EB-2013-XXXX F1-2-2 Table 1	2012 Restated Allocation (a)+(b)
		(a)	(b)		(c)
1	Business Support & Reg'ty Affairs	0.7		Strategy & Business Support	0.7
2	Water Resources & Aboriginal Affairs	1.2	(1.2)		0.0
3	Dam Safety & Emergency Prep	0.5		Dam Safety & Emergency Prep	0.5
4	Environment	0.6	(0.6)		0.0
5	Supply Chain	0.6	(0.6)		0.0
6	Hydroelectric Development	0.6	(0.3)	Hydro-Thermal Project Execution	0.2
7	Engineering Services	3.3		Engineering & Technical Services	3.3
8	EVP Office	0.6		SVP Office	0.6
9	Total	8.0	(2.7)		5.3

Note: The table does not include the impacts of the merger of Hydro Thermal business units

The following sections provide a brief description of each central support group. Section 3.6 describes the methodology used to allocate costs to the regulated and non-regulated facilities.

3.5.1 Senior Vice President - HTO's Office

Prior to 2012, budgeted Senior Vice President - HTO's Office costs included various expenses incurred by the EVP - Hydroelectric, including travel, administrative support and membership costs in various hydroelectric associations, such as the International Hydropower Association and Canadian Hydropower Association. In 2012, as part of the amalgamation of the Hydro and Thermal Business Units, the Executive Vice President – Hydro and Senior Vice President – Thermal offices were combined into one Senior Vice President- HTO office. Costs budgeted in this category are similar to those above. In 2013, there are expected to be two staff (year-end value).

3.5.2 HTO Engineering and Technical Services

Prior to 2012, the Hydroelectric Engineering Division provided specialized civil, mechanical, and electrical engineering support to the hydroelectric plant groups. As part of the 2012 Business Transformation and the amalgamation of the Hydroelectric and Thermal Business Units, a new Engineering and Technical Services Divison was formed by combining Engineering from the Hydroelectric Business Unit, Technical Services from the Thermal Business Unit, and the Project Management Office from the Hydroelectric Business Services and Water Resources Divisions. This new Division includes seven main departments:

- The Dams and Structures Department
- Power Equipment Department
- Balance of Plant Equipment Department
- Electrical, Protection and Controls Department
- Machine Dynamics and Component Integrity Department
- Performance & Testing Department
- Project Management Office

The Engineering and Technical Services Division has 125 staff (2013 year-end value), consisting of engineers, technicians, and clerks.

3.5.3 Dam Safety and Emergency Preparedness

The Dam Safety and Emergency Preparedness group, which has six staff (2013 year-end value), provides program oversight and guidance on dam safety and emergency preparedness at all of OPG's dams. The plant groups are responsible for the operation and maintenance of dams, and technical support is provided by the HTO Engineering and Technical Services Division.

3.5.4 Strategy and Business Support

Prior to the 2012 Business Transformation, the Business Support Division, provided business-level oversight, planning and reporting support for the EVP - Hydroelectric and the hydroelectric plant groups, including regulatory support for OPG's rate application. As part of the 2012 Business Transformation and the amalgamation of the Hydro and Thermal Business Units, the Thermal and Hydro Business Support groups were merged and renamed Strategy and Business Support. This Division continues to provide similar support services for HTO. This division is expected to have 19 staff (2013 year end value).

3.5.5 Hydro Thermal Project Execution

Prior to 2012, the Hydroelectric Development division identified, studied, planned, and oversaw the conceptual work, design and execution of hydroelectric re-development and new development projects (e.g. Niagara Tunnel project, PGS Rehabilitation, and Ranney Falls GS Expansion).

In 2012, as part of OPG's Business Transformation re-organization, Hydroelectric Development was divided into two parts - Hydro Thermal Project Execution Division and Business Development. OPG's Hydro Thermal Project Execution Division resulted from the amalgamation of Hydro project offices (i.e. accountable for project execution) with the Thermal Business Development Division. The Hydro Thermal Project Execution Division remains part of OPG's Hydro Thermal business unit. The Business Development department was rolled into Corporate Business Development.

Reporting to the Vice President of Hydro Thermal Project Execution, the group includes 22 staff (2013 year-end value) consisting of project managers, project engineers, and project specialists.

3.5.6 First Nations and Métis Relations / Water Resources

The First Nations and Métis Relations Group, which had seven staff, provided business level expertise and services for leading past grievance negotiations with First Nations, and administering payments associated with settled past grievances. This Division was moved to Corporate Relations and Communications as part of Business Transformation in 2012.

The Water Resources Department, which had nine staff, was previously part of Water Resources and Aboriginal Affairs in EB-2010-0008. The department provides support for: water management policy and planning, energy forecasting, and day-ahead coordination of hydroelectric resources. As part of the 2012 Business Transformation re-organization, the Water Resources department was transferred to Commercial Operations Business Unit.

3.5.7 Environment

Prior to 2012, the Environment Division, which had eight staff, provided environmental oversight and support for the EVP-Hydroelectric and the plant groups. This division was moved to the Commercial Operations and Environment Business Unit as part of the 2012 Business Transformation reorganization.

3.5.8 Hydroelectric Supply Chain

Prior to 2012, the Supply Chain Division was part of the Hydroelectric Business Unit and had 12 staff who provided procurement support activities and materials management activities for all the hydroelectric plant groups and Hydroelectric Development. This Division was moved to Business and Administrative Services in 2012 as part of the Business Transformation reorganization.

3.6 Allocation Methodology for HTO Central Support Costs

The method for allocating Hydroelectric Central Support Group Costs was reviewed by R.J. Rudden Associates in 2006 and Black & Veatch Corporation in 2009. In 2013, OPG's allocation methodology was again independently evaluated by HSG Group Inc. R.J. Rudden Associates recommended that as a general principle, direct assignment (i.e. time estimates or management estimates of full time equivalents dedicated to a particular group) should be used where practical and efficient, and base OM&A costs should be used to allocate all other central support group costs that cannot be directly assigned. The recommendations were implemented by OPG starting in 2006. R.J. Rudden also reviewed the allocation of Ottawa - St. Lawrence common costs to R.H. Saunders and the balance of the plant group, and its recommendations were adopted (see allocation methodology in section 3.4 above).

With respect to Hydroelectric central support costs, R.J. Rudden Associates, Black & Veatch, and HSG Group Inc. recommended the use of plant group base OM&A costs to allocate central costs that cannot be directly assigned or where it is inefficient to perform direct assignment. Prior to 2012, this methodology was used to allocate the costs for the office of the EVP - Hydroelectric, Dam Safety and Emergency Preparedness, First Nations and Metis Relations (formerly Aboriginal Relations), Business Support, Water Resources, and Environment. In the new HTO organization, this approved methodology continues to be used for the SVP- HTO office, Strategy and Business Support, and Dam Safety and Emergency Preparedness Divisions, except that Dam Safety costs are only allocated to facilities that have dams. Prior to 2012, a direct assignment approach was generally used for Engineering, Supply Chain, and Hydroelectric Development (except for Hydroelectric Development overhead costs). This approach continues to be used in the new HTO Engineering and Technical Services, and Hydro Thermal Project Execution Divisions.

3.6.1 Allocation of Engineering and Technical Services

The costs for Engineering services are allocated as follows:

- Estimates of engineering cost allocations for each year in the planning cycle are developed during the business planning/budgeting process. Each department in the Engineering Division develops time estimates for each of the plant groups (or plants in the case of R.H. Saunders) based on a high level review of each plant group's future work plans/projects and anticipated support requirements, as well as a review of previous year's historical engineering support costs for each plant group.
- Total engineering hours are then allocated to each plant group based on these reviews.
- The total engineering budget for the year is allocated using the ratio of estimated hours for each plant group divided by the total engineering hours. The 2014 and 2015 planned engineering allocations to each plant group are calculated by applying the 2013 ratios (i.e. the ratios developed as part of the 2013 - 2015 business planning process) to the forecast costs in 2014 and 2015, respectively.

3.6.2 Allocation of Hydro Thermal Project Execution

Prior to the 2012 Business Transformation reorganization, Hydroelectric Development OM&A costs were either directly attributed to the regulated stations where applicable, or allocated based on the total cost estimates for development projects. If a project was in the pre-concept or concept phase, and was related to a regulated facility or site, then its costs were directly attributed to that site (e.g. the PGS Reservoir Refurbishment and Expansion Study). The costs associated with the office of the Vice President - Hydroelectric Development and the general OM&A expenses were allocated based on estimated capital and OM&A project expenditures.

As a result of the 2012 reorganization, and the amalgamation of Hydro and Thermal, this group was divided into 2 separate groups, with the Niagara Tunnel and Lower Mattagami project departments merging with Thermal Project Development to form the Hydro Thermal Project Execution Division, which is part of the HTO Central Office. The Business Development group (responsible for projects in the pre-concept, concept and definition phase) moved to Corporate Business Development. The costs associated with the Hydro Thermal Project Execution Division continue to be allocated based on direct assignment of project costs, and for the office of the Vice President – Hydro Thermal Project Execution and other OM&A expenses based on estimated capital and OM&A project expenditures. Since the project portfolio varies year by year, the portion of general OM&A costs allocated to the regulated plants can also vary.

3.6.3 Allocation of Hydroelectric Supply Chain

The allocation of Supply Chain costs, prior to 2012, in Hydroelectric were based on management's time estimates. Approximately three staff were dedicated to procurement and material management activities related to the regulated operations at R.H. Saunders GS and the Niagara Plant Group. As a result of the 2012 Business Transformation, this division has been moved to the Business and Administrative Services Business Unit.

Table 1
Base OM&A - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Base OM&A:						
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**[1]	44.3	33.7	45.4	54.2	56.8	50.4
2	**Saunders GS**	15.1	16.4	14.8	17.6	17.8	18.1
3	**Subtotal**	59.4	50.1	60.2	71.9	74.6	68.6
	Newly Regulated Hydroelectric:						
4	**Ottawa-St.Lawrence Plant Group**[2]	30.2	34.4	32.8	37.7	37.8	37.6
5	**Central Hydro Plant Group**	18.9	22.4	21.1	24.5	24.2	24.7
6	**Northeast Plant Group**	19.0	21.3	21.9	25.1	23.8	23.6
7	**Northwest Plant Group**	31.8	27.9	27.2	26.0	27.5	27.8
8	**Subtotal**	100.0	106.0	102.9	113.2	113.4	113.7
9	**Total Base OM&A**	159.4	156.1	163.1	185.1	188.0	182.3
	OM&A Labour:[3]						
	Niagara Plant Group and Saunders GS:						
10	**Niagara Plant Group**	27.6	30.7	31.7	36.4	36.1	35.5
11	**Saunders GS**	8.7	9.3	9.6	10.6	10.8	11.0
12	**Subtotal**	36.3	40.0	41.3	47.0	46.9	46.5
	Newly Regulated Hydroelectric:						
13	**Ottawa-St.Lawrence Plant Group**[2]	17.2	19.3	20.3	24.5	24.9	24.3
14	**Central Hydro Plant Group**	11.9	13.0	13.7	16.9	16.5	16.7
15	**Northeast Plant Group**	11.8	13.3	14.2	17.5	16.8	16.2
16	**Northwest Plant Group**	12.2	14.3	15.7	17.9	18.8	18.6
17	**Subtotal**	53.0	60.0	63.9	76.8	76.9	75.9
18	**Total OM&A Labour**	89.3	100.0	105.1	123.7	123.8	122.4

Notes:

1 Niagara Plant Group 2011 Actual costs include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

3 Labour expense is included in Base OM&A.

Table 2
Base OM&A by Major Components - Previously Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	Labour	Materials	External Purchased Services	Other	Allocated Support Costs	Total Base OM&A
		(a)	(b)	(c)	(d)	(e)	(f)
	2010 Budget:						
1	**Niagara Plant Group**	30.1	2.6	7.4	0.2	6.9	47.2
2	**Saunders GS**	8.3	0.9	2.3	0.0	3.1	14.6
3	**Total**	38.4	3.5	9.7	0.2	10.0	61.8
	2010 Actual:						
4	**Niagara Plant Group**	27.6	3.3	5.7	1.1	6.6	44.3
5	**Saunders GS**	8.7	1.0	2.3	(0.0)	3.1	15.1
6	**Total**	36.3	4.3	8.0	1.1	9.7	59.4
	2011 Board Approved:						
7	**Niagara Plant Group**	31.3	2.4	12.7	0.3	6.8	53.5
8	**Saunders GS**	8.7	1.0	2.3	0.1	3.1	15.2
9	**Total**	40.0	3.4	15.1	0.4	9.9	68.7
	2011 Actual:						
10	**Niagara Plant Group**[1]	30.7	2.9	9.0	(17.9)	9.1	33.7
11	**Saunders GS**	9.3	0.9	2.2	0.6	3.4	16.4
12	**Total**	40.0	3.9	11.2	(17.4)	12.5	50.1
	2012 Board Approved:						
13	**Niagara Plant Group**	33.0	2.2	4.7	0.4	6.0	46.3
14	**Saunders GS**	9.1	1.0	2.4	0.1	3.2	15.8
15	**Total**	42.1	3.2	7.1	0.5	9.2	62.2
	2012 Actual:						
16	**Niagara Plant Group**	31.7	3.1	5.1	0.3	5.3	45.4
17	**Saunders GS**	9.6	1.1	2.0	(0.1)	2.2	14.8
18	**Total**	41.3	4.1	7.1	0.2	7.5	60.2
	2013 Budget:						
19	**Niagara Plant Group**	36.4	3.4	8.9	0.5	5.1	54.2
20	**Saunders GS**	10.6	1.1	2.8	0.0	3.2	17.6
21	**Total**	47.0	4.5	11.7	0.5	8.2	71.9
	2014 Plan:						
22	**Niagara Plant Group**	36.1	2.8	12.5	0.5	4.9	56.8
23	**Saunders GS**	10.8	1.1	2.8	0.0	3.1	17.8
24	**Total**	46.9	3.9	15.2	0.5	8.1	74.6
	2015 Plan:						
25	**Niagara Plant Group**	35.5	2.9	6.8	0.4	4.8	50.4
26	**Saunders GS**	11.0	1.1	2.8	0.0	3.3	18.1
27	**Total**	46.5	4.0	9.6	0.4	8.1	68.6

Notes:

1 Niagara Plant Group 2011 Actual costs include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

Table 3
Base OM&A by Major Components - Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	Labour	Materials	External Purchased Services	Other	Allocated Support Costs	Total Base OM&A
		(a)	(b)	(c)	(d)	(e)	(f)
	2010 Budget:						
1	**Ottawa-St.Lawrence Plant Group[1]**	18.3	1.6	0.7	0.1	9.6	30.2
2	**Central Hydro Plant Group**	12.4	2.1	2.3	2.1	2.6	21.5
3	**Northeast Plant Group**	12.6	0.9	0.9	2.0	2.8	19.3
4	**Northwest Plant Group**	14.3	1.2	1.5	1.9	3.8	22.7
5	**Total**	57.6	5.9	5.4	6.0	18.8	93.7
	2010 Actual:						
6	**Ottawa-St.Lawrence Plant Group[1]**	17.2	1.8	2.0	0.2	9.0	30.2
7	**Central Hydro Plant Group**	11.9	1.5	1.8	1.8	2.0	18.9
8	**Northeast Plant Group**	11.8	1.6	1.3	1.8	2.5	19.0
9	**Northwest Plant Group**	12.2	2.2	1.3	13.0	3.1	31.8
10	**Total**	53.0	7.2	6.3	16.8	16.7	100.0
	2011 Board Approved:[2]						
11	**Ottawa-St.Lawrence Plant Group[1]**	19.4	1.5	0.8	1.2	10.0	32.9
12	**Central Hydro Plant Group**	14.9	1.9	1.8	2.6	3.0	24.3
13	**Northeast Plant Group**	14.3	1.0	1.2	2.2	3.0	21.7
14	**Northwest Plant Group**	16.1	1.2	1.6	2.3	3.7	24.9
15	**Total**	64.7	5.6	5.5	8.3	19.7	103.7
	2011 Actual:						
16	**Ottawa-St.Lawrence Plant Group[1]**	19.3	1.8	2.4	1.1	9.7	34.4
17	**Central Hydro Plant Group**	13.0	1.6	2.4	2.9	2.5	22.4
18	**Northeast Plant Group**	13.3	1.9	1.0	2.3	2.7	21.3
19	**Northwest Plant Group**	14.3	2.1	2.0	6.1	3.3	27.9
20	**Total**	60.0	7.4	7.8	12.5	18.3	106.0
	2012 Board Approved:[3]						
21	**Ottawa-St.Lawrence Plant Group[1]**	20.5	1.6	1.2	1.1	10.1	34.5
22	**Central Hydro Plant Group**	14.7	2.2	2.5	2.5	2.6	24.5
23	**Northeast Plant Group**	15.0	1.2	1.0	4.5	3.1	24.8
24	**Northwest Plant Group**	16.4	1.2	1.4	2.3	3.8	25.1
25	**Total**	66.6	6.2	6.1	10.3	19.6	108.8
	2012 Actual:						
26	**Ottawa-St.Lawrence Plant Group[1]**	20.3	1.8	2.0	0.8	8.0	32.8
27	**Central Hydro Plant Group**	13.7	2.1	1.7	1.8	1.8	21.1
28	**Northeast Plant Group**	14.2	1.5	1.0	3.4	1.7	21.9
29	**Northwest Plant Group**	15.7	2.1	1.3	4.9	3.2	27.2
30	**Total**	63.9	7.5	6.0	10.9	14.7	102.9
	2013 Budget:						
31	**Ottawa-St.Lawrence Plant Group[1]**	24.5	1.8	2.6	0.3	8.4	37.7
32	**Central Hydro Plant Group**	16.9	2.2	1.0	2.6	1.8	24.5
33	**Northeast Plant Group**	17.5	1.6	1.5	2.7	1.7	25.1
34	**Northwest Plant Group**	17.9	1.4	1.4	2.0	3.3	26.0
35	**Total**	76.8	7.1	6.5	7.6	15.2	113.2
	2014 Plan:						
36	**Ottawa-St.Lawrence Plant Group[1]**	24.9	1.8	2.6	0.2	8.2	37.8
37	**Central Hydro Plant Group**	16.5	2.2	1.0	2.6	1.8	24.2
38	**Northeast Plant Group**	16.8	1.5	0.9	2.9	1.7	23.8
39	**Northwest Plant Group**	18.8	1.5	1.5	2.3	3.4	27.5
40	**Total**	76.9	7.1	6.1	8.1	15.2	113.4
	2015 Plan:						
41	**Ottawa-St.Lawrence Plant Group[1]**	24.3	1.8	2.6	0.2	8.6	37.6
42	**Central Hydro Plant Group**	16.7	2.3	1.0	2.7	1.9	24.7
43	**Northeast Plant Group**	16.2	1.5	1.1	3.1	1.7	23.6
44	**Northwest Plant Group**	18.6	1.6	1.4	2.6	3.6	27.8
45	**Total**	75.9	7.2	6.2	8.7	15.8	113.7

Notes:
1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.
2 As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.
3 As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.

Numbers may not add due to rounding.

Table 4

Staff Summary - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric[1]

Line No.	Group	2010 Budget	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved	2012 Actual[2]	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Niagara Plant Group Staff FTEs**	254.1	238.7	254.2	238.1	251.4	233.1	232.8	230.8	230.8
2	**Saunders GS Staff FTEs**	68.8	67.8	68.8	64.6	68.8	67.0	68.8	68.8	68.8
3	**Total Direct FTEs - Niagara Plant Group and Saunders GS**	322.9	306.5	323.0	302.7	320.2	300.1	301.6	299.6	299.6
4	**Allocated Central Office Staff FTEs[3]**	N/A	53.2	N/A	66.8	N/A	43.7	45.2	43.5	41.3
5	**Total Staff FTEs - Niagara Plant Group and Saunders GS**	N/A	359.7	N/A	369.4	N/A	343.8	346.8	343.1	340.9
	Newly Regulated Hydroelectric:									
6	**Ottawa-St.Lawrence Plant Group Staff FTEs[4]**	N/A	178.2	N/A	178.8	N/A	178.8	168.6	168.6	162.6
7	**Central Hydro Plant Group Staff FTEs[3]**	N/A	103.0	N/A	111.6	N/A	103.0	104.8	101.7	101.6
8	**Northeast Plant Group Staff FTEs[3]**	N/A	105.2	N/A	112.0	N/A	112.6	116.3	117.3	108.2
9	**Northwest Plant Group Staff FTEs[3]**	N/A	117.3	N/A	125.4	N/A	127.2	128.5	132.3	129.8
10	**Total Direct FTEs - Newly Regulated Hydroelectric**	N/A	503.7	N/A	527.8	N/A	521.6	518.3	520.0	502.2
11	**Allocated Central Office Staff FTEs[3]**	N/A	80.6	N/A	89.6	N/A	79.4	78.5	79.6	80.0
12	**Total Staff FTEs - Newly Regulated Hydroelectric**	N/A	584.3	N/A	617.4	N/A	600.9	596.8	599.5	582.2
13	**Total Staff FTEs** (line 5 + line 12)	N/A	944.0	N/A	986.8	N/A	944.7	943.6	942.6	923.0

Notes:

1 Staff FTEs include staff deployed on Base OM&A, Project OM&A and capital projects. Staff FTEs include regular and non-regular staff.

2 The Central Office Allocated Staff FTEs 2012 Actual have been corrected from those reported to the OEB in April 2013 with a net increase of 10 FTEs for Engineering staff.

3 FTEs have been allocated using the same percentages as Base OM&A costs. Allocated FTEs were not computed for budget purposes prior to 2012-2014 business planning.

4 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS FTEs are excluded.

COMPARISON OF BASE OM&A – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of base OM&A cost for the regulated hydroelectric facilities for 2010 - 2015.

2.0 OVERVIEW

This evidence supports the approval sought for regulated hydroelectric base OM&A for the test period. Exhibit F1-2-2 Tables 1 through 8 set out the comparison of base OM&A by organizational unit over the 2010 - 2015 period. As per section 2.7.1 of the OEB Filing Guidelines, period-over-period changes under 10 per cent are not explained. The tables do not include corporate allocations, which are discussed in Exhibit F3-1-1.

Exhibit F1-2-2 Tables 1 and 2 set out the Hydro Thermal Operations ("HTO") Central Support Group's OM&A budgets by organizational or functional area for the historical, bridge year, and test periods. These costs are allocated to the regulated hydroelectric stations using the methodology described in Ex. F1-2-1. Table 1 shows the allocations to the Niagara Plant Group and R.H. Saunders, and Table 2 shows the allocations to the newly regulated stations.

Exhibit F1-2-2 Table 3 identifies the hydroelectric base OM&A costs for the Niagara Plant Group for the historical, bridge year, and test periods. It includes the portion of HTO Central Support Group OM&A expenses allocated to the Niagara Plant Group for the same period.

Exhibit F1-2-2 Table 4 sets out the hydroelectric base OM&A costs for R.H. Saunders for the historical, bridge year, and test periods. It includes a base OM&A allocation from the Ottawa - St. Lawrence Plant Group ("OSPG") support organizations and from the HTO Central Support Groups as per the methodology described in Ex. F1-2-1.

Exhibit F1-2-2 Table 5 sets out the Hydroelectric base OM&A costs for balance of the Ottawa-St.Lawrence Plant Group ("OSPG") facilities for the historical, bridge year, and test periods. These facilities are included with newly regulated hydroelectric. The costs include a base OM&A allocation from the OSPG support organizations and from the HTO Central Support Groups as per the methodology described in Ex. F1-2-1.

Exhibit F1-2-2 Tables 6 through 8 identify the HTO base OM&A costs for the balance of newly regulated hydroelectric stations for the historical, bridge year, and test periods. These facilities are managed by the Central Hydro, Northeast, and Northwest Plant Groups. In addition to an allocation of HTO Central Support Group costs, the base OM&A costs include an allocation of plant group costs between the newly regulated and the OPA contracted facilities as per the methodology described in Ex. F1-2-1.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2015 Plan versus 2014 Plan

HTO Central Support Groups

Cost changes from 2014 to 2015 for allocations from the Hydro Thermal Operations ("HTO") Central Support Groups are under 10 per cent.

Niagara Plant Group

The decrease of $6.2M at the Niagara Plant Group from 2014 to 2015 is mainly attributed to the decrease of $5.8M in administration costs. The 53 per cent reduction in administration spending is due to the divestiture of the Merritville Road bridge planned in 2014. Costs for operations increased by $0.8M or 11 per cent due to the cost sharing under the NYPA Joint Works program for the replacement of an ice breaker used to support operations around the International Control Dam. Cost changes in Niagara Plant Group maintenance are less than 10 per cent.

R.H. Saunders Generating Station

Cost changes from 2014 to 2015 for R.H. Saunders operating, maintenance and administration, and allocations from the OSPG support organizations are under 10 per cent.

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

Cost changes from 2014 to 2015 for the Ottawa St. Lawrence Plant Group (excluding Saunders GS), maintenance and administration, and allocations from the OSPG support organizations are under 10 per cent.

Central Hydro Plant Group

Cost changes from 2014 to 2015 in the Central Hydro Plant Group operating, maintenance, and administration costs are less than 10 per cent.

Northeast Plant Group

Cost changes from 2014 to 2015 in the Northeast Plant Group operations, maintenance, and administration costs are less than 10 per cent.

Northwest Plant Group

Cost changes from 2014 to 2015 in the Northwest Plant Group operations, maintenance, and administration costs are less than 10 per cent.

2014 Plan versus. 2013 Budget

HTO Central Support Groups

Cost changes from 2013 to 2014 for allocations from the HTO Central Support Groups are under 10 per cent.

Niagara Plant Group

Administration costs for the Niagara Plant Group are planned to increase by $2.4M or 27 per cent from 2013 to 2014 due to the Niagara Bridge Divestiture Program which increases from $3.1M in 2013 to $5.8M in 2014. Cost changes in Niagara Plant Group operations and maintenance are less than 10 per cent.

R.H. Saunders Generating Station

Cost changes from 2013 to 2014 for R.H. Saunders operating, maintenance and administration, and allocations from the OSPG support organizations are under 10 per cent.

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

Cost changes from 2013 to 2014 for the Ottawa St. Lawrence Plant Group (excluding Saunders GS), maintenance and administration, and allocations from the OSPG support organizations are under 10 per cent.

Central Hydro Plant Group

Cost changes from 2013 to 2014 in the Central Hydro Plant Group operating, maintenance, and administration costs are less than 10 per cent.

Northeast Plant Group

Administration costs for the Northeast Plant Group are planned to decrease by $0.9M (14 per cent) from 2013 to 2014 due to an increase in the allocation of plant group support costs (e.g. Engineering) to the Lower Mattagami River OPA contracted stations, as more new Lower Mattagami units come into service in 2014. Cost changes in Northeast Plant Group operations and maintenance are less than 10 per cent.

Northwest Plant Group

Cost changes from 2013 to 2014 in the Northwest Plant Group operating, maintenance, and administration costs are less than 10 per cent.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget versus 2012 Actual

HTO Central Support Groups

Cost changes from 2012 to 2013 for allocations from the HTO Central Support Groups are under 10 per cent.

Niagara Plant Group

Niagara Plant Group administration costs are planned to increase by $3.2M to $8.7M in 2013 compared to the 2012 actual of $5.5M. The change is due to the Niagara Bridge Divestiture Program which increases from $0M in 2012 to $3.1M in 2013. Operations costs will increase by $2.1M or 40 per cent in 2013 primarily due to delays in filling operator vacancies due to

Business Transformation. Maintenance costs are planned to increase in 2013 by $3.7M or 13 per cent due to an increase in NPG small maintenance projects executed under the base OM&A budget, an increase in maintenance work instead of major project work, and an increase in labour rates.

R.H. Saunders Generating Station

R.H. Saunders operations costs are planned to increase by $0.4M, or 15 per cent and maintenance costs are planned to increase by $1.7M or 17 per cent from 2012 actual to 2013 budget, as a result of expected increases in labour rates as described above, and a modest increase on $0.3M for small base maintenance, non recurring work in 2013. Administration costs associated with the St. Lawrence Power Development Visitor Centre are expected to decrease by $0.1M or 33 per cent from 2012 actual to 2013 budget. This is a result of expected efficiencies and lessons learned from operating the centre since it came into service. Cost changes for allocations from the OSPG support organizations are expected to have an overall increase of $0.6M or 61 per cent from 2012 actual to 2013 budget. This is a result of unfilled vacancies in 2012, increased labour rates expected for 2013, and a minor reallocation of the support groups as described in exhibit F1-2-1 section 3.3. The primary change being HR Support Services and Business Support are now included under the Plant Group Management.

Ottawa-St.Lawrence Plant Group (excluding R.H Saunders GS)

Ottawa St. Lawrence Plant Group maintenance costs are budgeted to increase by $4.1M or 19 per cent from the 2012 actual spend. This is a result of unfilled vacancies in 2012, an increase in labour rates for 2013, and an increase in base OM&A funding for small maintenance, non recurring work in 2013. OSPG support organizations are expected to have an overall increase of $0.5M or 11 per cent from 2012 actual to 2013 budget. This is a result of unfilled vacancies in 2012, increased labour rates expected for 2013, and a minor reallocation of the support groups as described in exhibit F1-2-1 section 3.3. The primary organizational change is that Human Resources Support Services and Business Support are now included under Plant Group Management.

Central Hydro Plant Group

Central Hydro Plant Group operations costs are planned to increase in 2013 by $0.5M (25 per cent due to an unfilled vacancy in 2012, in addition to increases in labour rates. Maintenance costs are set to increase by $2.6M (21 per cent) due to filling of vacancies from 2012, an increased maintenance work program, and labour rate increases. Administration cost changes are less than 10 per cent.

Northeast Plant Group

Northeast Plant Group operations costs are planned to increase by $0.4M (22 per cent) in 2013 compared to 2012 actual, due to increases in labour rates. Administration costs are expected to increase by $1.8M (38 per cent) in 2013 due to increases in labour rates, the filling of vacant positions, and an increase in the allocation of common support costs. Cost changes for maintenance are less than 10 per cent.

Northwest Plant Group

Northwest Plant Group administration costs are planned to decrease by $2.4M in 2013 as compared to 2012 due to a $3.0M addition to a First Nation provision in 2012. Operations costs are expected to increase by $0.8M or 29 per cent in 2013 primarily due to filling of vacancies and increases in labour rates. Cost changes in maintenance are less than 10 per cent.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual versus 2012 Board Approved

HTO Central Support Groups

The 2012 HTO Central Support Groups allocated cost variances are more than 10 per cent under both the plan presented in EB-2010-0008 for the Niagara Plant Group and Saunders GS, or the budget for the newly regulated stations. This is mainly due to the Business Transformation reorganization in 2012. As described in Exhibits A1-4-2 and A4-1-1, a number of central support groups (e.g. Environment, Supply Chain, Water Resources and First Nations and Metis Relations) were centralized under corporate groups during 2012.

<u>Niagara Plant Group</u>

The 2012 actual costs for Niagara Plant Group were $0.2M under the plan presented in EB-2010-0008. Niagara Plant Groups administration costs increased by $1.0M of which $0.7M is an increase to security surveillance at the Plant Group. Operations costs decreased by $2.0M due to operator vacancies at the Niagara Plant Group control centre. The cost changes for maintenance were less than 10 per cent.

<u>R.H. Saunders Generating Station</u>

The 2012 actual costs, including Plant Group Common Costs for Saunders GS, were $13.5M or $0.3M less than the $13.8M plan for 2012 presented in EB-2010-0008. The 2012 variances for operations and maintenance were less than 10 per cent. Administration costs, associated with the St. Lawrence Power Development Visitor Centre, were $0.3M versus the $0 in the 2012 plan submitted in EB-2010-0008. Allocated Plant Group Common Actual Costs in 2012 were $1.0M or 19 per cent less than the plan of $1.2M submitted in the EB-2010-0008. The variance was mainly due to vacancies in the Asset Management & Technical Services department in 2012.

<u>Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)</u>

The 2012 actual versus. budget cost variances for the Ottawa St. Lawrence Plant Group (excluding Saunders GS), maintenance and administration, and allocations from the OSPG support organizations were under 10 per cent.

<u>Central Hydro Plant Group</u>

Operations costs in 2012 for Central Hydro Plant Group were $0.2M (11 per cent) under budget due to an operator vacancy and lower overtime use. Administration costs were $1.2M (20 per cent) under budget largely due to unfilled vacancies, transfer of People and Culture, and Controllership staff to corporate budgets as part of Business Transformation, as well as, underspending on purchased services due to deferred work. The maintenance cost variance was less than 10 per cent.

<u>Northeast Plant Group</u>

Operations costs in 2012 were under budget by $0.2M (11 per cent) due to lower overtime and lower payroll burden costs. Administration costs were $0.8M (14 per cent) under budget in 2012 due to delays in filling vacancies due to Business Transformation. The maintenance cost variance was less than 10 per cent.

Northwest Plant Group

The 2012 actual costs for Northwest Plant Group are $2.7M over plan. Administration costs were over budget by $2.7M due to the addition of $3.0M for a First Nations provision in 2012. Operations costs were lower in 2012 due to delays in filling vacancies due to Business Transformation. The maintenance cost variance was less than 10 per cent.

2012 Actual versus 2011 Actual

Hydroelectric Central Support Groups

Allocations from the HTO/Hydroelectric Central Support Groups decreased by more than 10 per cent for both the Niagara Plant Group and Saunders GS, and the newly regulated stations. This was mainly due to the Business Transformation reorganization in 2012. As described in Exhibits A1-4-2 and A4-1-1, a number of central support groups (e.g. Environment, Supply Chain, Water Resources, and First Nations and Metis Relations) were centralized under corporate groups during 2012.

Niagara Plant Group

Administration costs for the Niagara Plant Group increased by $15.8M from 2011 to 2012 due to an extraordinary credit of $19M in 2011 related to the reversal of the provision for the environmental cleanup of Lake Gibson, offset somewhat by a $3.5M decrease in the Niagara Bridge Divestiture Program. The cost changes in Niagara Plant Group maintenance and operations are less than 10 per cent.

R.H. Saunders Generating Station

Operating and maintenance cost changes from 2011 to 2012 for R.H. Saunders were under 10 per cent. Administration costs associated with the St. Lawrence Power Development Visitor Centre were $0.3M in 2012 as compared to $0M in the 2011 actuals. The Visitor

Centre was in operation in 2011, however operating costs were relatively minor as the facility ramped its presence in the community. The first full year of operation was 2012. As well, allocations from the OSPG support organizations were $0.2M or 14 per cent less in 2012 versus 2011. This was primarily a result of unfilled vacancies in the Asset Management & Technical Services department in 2012.

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

Cost changes from 2011 to 2012 for operations and maintenance the Ottawa St. Lawrence Plant Group operations and maintenance were under 10 per cent. Allocations from the OSPG support organizations were $0.5M or 10 per cent less in 2012 versus 2011. This was primarily a result of unfilled vacancies in the Asset Management & Technical Services department in 2012.

Central Hydro Plant Group

Administration costs decreased by $0.4M (16 per cent) from 2011 to 2012 for Central Hydro Plant Group due to the transfer of People and Culture, and Controllership staff to corporate budgets as part of Business Transformation. Operations and Maintenance cost changes were less than 10 per cent year over year.

Northeast Plant Group

Maintenance costs for the Northeast Plant Group increased by $1.7M (14 per cent) from 2011 to 2012 due to higher than planned removal costs related to the Matabitchuan Penstock Replacement capital project (removal costs are charged to base OM&A). Cost changes for operations and administration were less than 10 per cent.

Northwest Plant Group

Administrative costs for the Northwest Plant Group decreased by $0.9M due to the First Nation provision changes of $4.0M in 2011 compared to $3.0M in 2012. Operations and maintenance cost changes were less than 10 per cent.

2011 Actual versus 2011 Board Approved

Hydroelectric Central Support Groups

For the Hydroelectric Central Support Group costs, allocations for Niagara Plant Group and Saunders GS in 2011 were $2.7M or 31 per cent above the Board approved plan in EB-2010-0008. This was mainly due to unplanned directly allocated costs related to concept studies of the rehabilitation of the Sir Adam Beck Pump GS reservoir performed in the former Hydroelectric Development Division. In contrast, allocations to the newly regulated stations in 2011 were $1.6M or 11 per cent lower than OPG's budget. This variance was due the combination of lower than planned spending in the support groups due staff vacancies, and lower percentages being allocated due lower that planned spending in the newly regulated plant groups.

Niagara Plant Group

The Niagara Plant Group Administration spending in 2011 was $21.7M under budget mostly due to an extraordinary credit of $19M related to the reversal of the provision for the environmental cleanup of Lake Gibson. In addition, the Niagara Bridge Divestiture Program accounted for a $3.4M variance as the Niagara Falls Road Bridge was divested. The $2.1M or 28 per cent under variance in operations costs is due staff vacancies and the realignment of the Niagara Plant Group budget described below. Maintenance cost variances were under 10 per cent.

R.H. Saunders Generating Station

OM&A cost variances, actual versus budget for 2011, for R.H. Saunders operations and allocated OSPG common support costs were under 10 per cent for 2011 actual vs. board approved plan. Maintenance costs were $1.1M or 11 per cent higher than plan due to an accounting reclassification of removal costs from depreciation expense to OM&A (see Ex. F4-1-1, section 3.1).

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

OM&A cost variances, actual versus budget for 2011, for the Ottawa St. Lawrence Plant Group, including allocated OSPG common support costs, were under 10 per cent.

Central Hydro Plant Group

Operations costs were $0.3M (13 per cent) over budget in 2011 due to an increased volume of field operations for North Bay, Coniston, and Campbellford stations, as well as the purchase and installation of new revenue metering systems at Gravenhurst stations. Administration costs were under budget by $0.8M (14 per cent) largely due to vacancies and underspending on purchased services due to deferred work. The maintenance cost variance for 2011 was under 10 per cent.

Northeast Plant Group

The Northeast Plant Group operations spending in 2011 was $0.2M (11 per cent) under budget due to fewer than planned overtime hours worked. Maintenance and administration variances are less than 10 per cent.

Northwest Plant Group

Northwest Plant Group administrative spending in 2011 was $3.4M over budget mostly due to the addition of a $5.0M First Nation provision, offset by $1.0M credit related to another First Nation provision based on the final settlement. The $0.4M or 14 per cent variance in operations costs was due to unfilled vacancies and lower overtime than planned. Maintenance cost variances were under 10 per cent.

2011 Actual versus 2010 Actual

Hydroelectric Central Support Groups

For the Hydroelectric Central Support Group costs, allocations to the Niagara Plant Group and Saunders GS in 2011 were $2.8M or 32 per cent higher than 2010 due to unplanned, directly allocated costs related to concept studies of the rehabilitation of the Sir Adam Beck Pump GS reservoir. For the newly regulated stations, the change in Hydroelectric Central Support Groups allocations were under 10 per cent

Niagara Plant Group

Niagara Plant Group administration costs decreased by $16.1M in 2011 from the 2010 actual of $5.8M. The change is due to the extraordinary credit of $19M related to the reversal of the provision for the environmental cleanup of Lake Gibson, offset by the Niagara Bridge Divestiture Program which increased from $0M in 2010 to $3.5M in 2011. The increase in 2011 Maintenance costs is due to several factors, including: removal costs for capital projects being charged to OM&A starting in 2011, the NYPA Joint Works program costs increased in 2011, along with other maintenance activities. The decrease in operations costs of $0.7M or 13 per cent is due to a lower than planned staffing levels..

R.H. Saunders Generating Station

Cost changes from 2010 to 2011 for R.H. Saunders operations and allocations from the OSPG support organizations were under 10 per cent. However, maintenance costs were higher by $1.1M or 11 per cent in 2011 versus 2010 due to an accounting reclassification of removal costs from depreciation expense to OM&A (see Ex. F4-1-1, section 3.1). The 2011 removal costs were associated with the Protections and Controls capital project.

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

Maintenance costs for the Ottawa-St. Lawrence Plant Group, were $3.2M or 18 per cent higher in 2011 versus 2010. The primary driver is removal costs charged to OM&A starting in 2011. Also in 2011, maintenance resources were pre-hired in anticipation of upcoming retirements. Operating costs were $0.3M or 10 per cent higher in 2011 due to the operations at Chenaux GS control centre. The timing associated with filling operator vacancies resulted in fewer labour hours charged in 2010 than 2011. In addition, labour costs were higher in 2011 due to higher labour rates and increased overtime at the Chenaux control centre. Allocations from the OSPG support organizations are $0.8M or 17 per cent higher in 2011 versus 2010. This was due to Asset Management and Technical Services hiring staff in 2011 for compliance management and programming. As well, there were lower Hydro Quebec recoveries in 2011 than 2010.

Central Hydro Plant Group

Operations costs increased by $0.6M (37 per cent) in 2011 over the 2010 actuals due to the addition of one operator, increases to labour rates and burdens, and addition field work performed. Administration costs increased by $1.7M (47 per cent) due to the hiring of additional staff, which were only partially included in 2010 actuals, and increased labour rates and burdens. Maintenance cost changes were under 10 per cent.

Northeast Plant Group

Northeast Plant Group maintenance costs increased by $1.3M in 2011 (13 per cent) due to an increase in maintenance work on stations and capital project removal costs being charged to base OM&A starting in 2011. Administration costs increased by $0.6M (14 per cent) due to the hiring of additional staff (e.g. Engineers, Project Officers, etc.) to support maintenance and project activities at the stations. The operations cost changes were less than 10 per cent.

Northwest Plant Group

Northwest Plant Group administration costs decreased by $6.9M due to the First Nation provision changes in 2011 of $4.0M compared to 2010 of $11.3M. The increase in 2011 maintenance costs is due to capital project removal costs being charged to OM&A starting in 2011, a dam safety periodic review moved from 2010 to 2011, along with an increase in maintenance staff and activities in 2011. Operations cost changes were less than 10 per cent.

2010 Actual versus 2010 Budget

Hydroelectric Central Support Groups

For the Hydroelectric Central Support Groups OM&A costs allocated to the Niagara Plant Group and Saunders GS, the actual versus budget variances were under 10 per cent for 2010. For the newly regulated stations, the support groups' allocation were $1.7M or 12 per cent less than budget. The lower than planned spending in the central support groups was due to unfilled vacancies in 2010.

Niagara Plant Group

Niagara Plant Group operations costs in 2010 were $0.9M less then budget due to lower than planned staffing levels and reduced spending in the NYPA Joint Works program. Maintenance and administration cost variances were under 10 per cent.

R.H. Saunders Generating Station

OM&A cost variances, actual versus budget, for R.H. Saunders, including allocated OSPG common support costs, were under 10 per cent for 2010.

Ottawa-St.Lawrence Plant Group (excluding R.H. Saunders GS)

Ottawa St Lawrence Plant Group operations and maintenance cost variances, 2010 actuals versus the 2010 budget, were less than 10 per cent However, OSPG support groups allocations were 0.4M or 11 per cent less in 2010 than budgeted. This was a result of timing with vacancies being filled in the Asset Management and Technical Services department.

Central Hydro Plant Group

Administration costs in 2010 were $1.9M (35 per cent) under budget due to vacant positions, unused purchases services budgets as a result of deferred work, and materials costs budgeted into administration but charged into maintenance. Operations and Maintenance cost variance were both under 10 per cent.

Northeast Plant Group

Northeast Plant Group operations costs in 2010 were $0.2M (13 per cent) and Administration costs were $0.6M (12 per cent) under budget due to lower than planned labour rates and payroll burden costs. The maintenance variance for 2010 was less than 10 per cent.

Northwest Plant Group

Northwest Plant Group administrative spending in 2010 was $10.9M over budget due to a $11.3M First Nation provision. Operations and maintenance variances were under 10 per cent.

Table 1
Comparison of Base OM&A ($M)
Central Support Groups - Previously Regulated Hydroelectric (Niagara Plant Group and Saunders GS)

Line No.	Group	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Strategy & Business Support[1,2]**	1.9	(0.4)	1.5	0.4	1.9	(0.0)	1.9	(1.4)	0.5
2	**Dam & Public Safety[2]**	0.5	(0.1)	0.4	0.1	0.5	(0.0)	0.5	(0.0)	0.5
3	**Environment[1]**	0.5	(0.0)	0.4	0.0	0.5	(0.1)	0.5	(0.5)	0.0
4	**Supply Chain[1]**	0.7	0.0	0.7	0.2	0.7	0.1	0.8	(0.8)	0.0
5	**Hydro-Thermal Project Execution[2]**	1.2	(0.0)	1.2	2.5	1.3	2.4	3.7	(3.2)	0.5
6	**Engineering & Technical Services[2]**	3.6	0.4	4.0	(0.4)	3.2	0.4	3.6	1.3	4.9
7	**SVP Office[2]**	0.6	(0.2)	0.3	0.0	0.6	(0.2)	0.4	(0.2)	0.1
8	**Total**	8.9	(0.3)	8.6	2.8	8.7	2.7	11.3	(4.8)	6.5

Line No.	Group	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
9	**Strategy & Business Support[1,2]**	1.9	(1.4)	0.5	0.1	0.6	0.2	0.7	0.0	0.7
10	**Dam & Public Safety[2]**	0.5	(0.0)	0.5	0.0	0.5	0.0	0.5	(0.1)	0.4
11	**Environment[1]**	0.6	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Supply Chain[1]**	0.6	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Hydro-Thermal Project Execution[2]**	0.6	(0.0)	0.5	(0.2)	0.3	(0.1)	0.2	(0.1)	0.1
14	**Engineering & Technical Services[2]**	3.3	1.6	4.9	0.2	5.1	(0.2)	4.9	0.1	5.0
15	**SVP Office[2]**	0.6	(0.4)	0.1	0.0	0.1	0.0	0.2	0.0	0.2
16	**Total**	8.0	(1.5)	6.5	0.1	6.6	(0.1)	6.5	(0.1)	6.4

Notes:

1 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.

2 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

Numbers may not add due to rounding.

Table 2
Comparison of Base OM&A ($M)
Central Support Groups - Newly Regulated Hydroelectric

Line No.	Group	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Budget	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Strategy & Business Support**[3,4]	3.2	(0.5)	2.7	0.8	4.0	(0.5)	3.4	(2.6)	0.8
2	**Dam & Public Safety**[4]	0.8	(0.1)	0.7	0.2	0.9	(0.0)	0.9	(0.0)	0.9
3	**Environment**[3]	0.8	(0.0)	0.8	0.0	0.9	(0.1)	0.8	(0.8)	0.0
4	**Supply Chain**[3]	0.9	(0.2)	0.7	(0.0)	0.8	(0.2)	0.6	(0.6)	0.0
5	**Hydro-Thermal Project Execution**[4]	0.1	(0.1)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0
6	**Engineering & Technical Services**[4]	7.3	(0.5)	6.8	(0.2)	7.0	(0.4)	6.6	1.4	8.0
7	**SVP Office**[4]	0.9	(0.4)	0.6	0.1	1.0	(0.3)	0.7	(0.4)	0.2
8	**Total**	14.0	(1.7)	12.3	0.8	14.6	(1.6)	13.1	(3.1)	10.0

Line No.	Group	2012 Budget	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
9	**Strategy & Business Support**[3,4]	4.0	(2.7)	1.3	(0.3)	1.0	0.3	1.3	0.3	1.6
10	**Dam & Public Safety**[4]	1.0	(0.5)	0.5	0.4	0.9	0.0	0.9	0.0	0.9
11	**Environment**[3]	1.0	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Supply Chain**[3]	0.8	(0.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Hydro-Thermal Project Execution**[4]	0.0	0.5	0.5	(0.4)	0.1	0.0	0.1	0.0	0.1
14	**Engineering & Technical Services**[4]	7.1	(2.2)	4.9	2.9	7.8	(0.2)	7.6	(0.0)	7.6
15	**SVP Office**[4]	0.5	(0.4)	0.1	0.1	0.3	0.1	0.3	0.1	0.4
16	**Total**	14.5	(7.1)	7.4	2.7	10.0	0.2	10.2	0.4	10.6

Notes:

1 As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.

2 As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.

3 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.

4 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

Table 3
Comparison of Base OM&A ($M)
Niagara Plant Group

Line No.	Group	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group:									
1	**Operations**	6.8	(0.9)	5.9	(0.7)	7.3	(2.1)	5.2	0.1	5.3
2	**Maintenance**	27.2	(1.2)	26.0	3.7	28.0	1.7	29.7	(0.3)	29.3
3	**Administration[1]**	6.3	(0.5)	5.8	(16.1)	11.4	(21.7)	(10.3)	15.8	5.5
4	**Total Plant Group**	40.3	(2.6)	37.7	(13.1)	46.7	(22.1)	24.6	15.5	40.1
	Allocated Central Support Group Costs:									
5	**Strategy & Business Support[2,3]**	1.4	(0.2)	1.2	0.2	1.4	(0.0)	1.4	(1.1)	0.3
6	**Dam & Public Safety[3]**	0.4	(0.0)	0.3	0.1	0.4	(0.0)	0.4	(0.0)	0.4
7	**Environment[2]**	0.3	(0.0)	0.3	0.0	0.4	(0.0)	0.3	(0.3)	0.0
8	**Supply Chain[2]**	0.5	0.0	0.5	0.1	0.5	0.2	0.7	(0.7)	0.0
9	**Hydro-Thermal Project Execution[3]**	1.2	(0.0)	1.2	2.5	1.3	2.4	3.7	(3.2)	0.5
10	**Engineering & Technical Services[3]**	2.7	0.1	2.8	(0.5)	2.4	(0.0)	2.3	1.6	4.0
11	**SVP Office[3]**	0.4	(0.2)	0.3	0.0	0.4	(0.1)	0.3	(0.2)	0.1
12	**Total Allocated Costs**	6.9	(0.3)	6.6	2.5	6.8	2.3	9.1	(3.8)	5.3
13	**Total**	47.2	(2.9)	44.3	(10.6)	53.5	(19.8)	33.7	11.7	45.4

Line No.	Group	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group:									
14	**Operations**	7.3	(2.0)	5.3	2.1	7.5	0.3	7.7	0.8	8.6
15	**Maintenance**	28.5	0.8	29.3	3.7	33.0	0.0	33.0	(1.2)	31.9
16	**Administration[1]**	4.5	1.0	5.5	3.2	8.7	2.4	11.1	(5.8)	5.2
17	**Total Plant Group**	40.3	(0.2)	40.1	9.1	49.2	2.6	51.8	(6.2)	45.7
	Allocated Central Support Group Costs:									
18	**Strategy & Business Support[2,3]**	1.3	(1.0)	0.3	0.1	0.4	0.1	0.5	(0.0)	0.5
19	**Dam & Public Safety[3]**	0.4	(0.0)	0.4	0.0	0.4	0.0	0.4	(0.1)	0.3
20	**Environment[2]**	0.4	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Supply Chain[2]**	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Hydro-Thermal Project Execution[3]**	0.6	(0.0)	0.5	(0.2)	0.3	(0.1)	0.2	(0.1)	0.1
23	**Engineering & Technical Services[3]**	2.5	1.5	4.0	(0.1)	3.8	(0.1)	3.7	0.0	3.7
24	**SVP Office[3]**	0.4	(0.3)	0.1	0.0	0.1	0.0	0.1	(0.0)	0.1
25	**Total Allocated Costs**	6.0	(0.7)	5.3	(0.2)	5.1	(0.1)	4.9	(0.1)	4.8
26	**Total**	46.3	(0.9)	45.4	8.8	54.2	2.5	56.8	(6.3)	50.4

Notes:
1. Niagara Plant Group 2011 Actual costs include an extraordinary credit of $19.0M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).
2. As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.
3. As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
   (1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
   (2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
   (3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
   (4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
   (5) the SVP Office was formerly the EVP Office.

Table 4
Comparison of Base OM&A ($M)
Saunders GS

Line No.	Group	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Station:									
1	**Operations**	2.2	0.0	2.2	0.0	2.4	(0.2)	2.2	0.2	2.4
2	**Maintenance**	9.3	0.4	9.7	1.1	9.7	1.1	10.8	(1.0)	9.8
3	**Administration**	0.0	0.1	0.1	(0.1)	0.0	0.0	0.0	0.3	0.3
4	**Total Station**	11.5	0.5	12.0	1.0	12.1	0.9	13.0	(0.5)	12.5
	Allocated Plant Group Common Costs:									
5	**Plant Group Management**	0.2	0.0	0.2	(0.0)	0.2	(0.0)	0.2	0.0	0.2
6	**Business Support**	0.1	(0.0)	0.1	(0.0)	0.1	(0.1)	0.1	0.0	0.1
7	**HR Support Services**	0.1	0.0	0.2	0.0	0.2	0.0	0.2	(0.0)	0.2
8	**Asset Mgmt & Technical Support**	0.7	(0.1)	0.6	0.1	0.7	0.0	0.7	(0.2)	0.6
9	**Total Plant Group Allocated Costs**	1.1	(0.0)	1.1	0.1	1.2	(0.0)	1.2	(0.2)	1.0
	Allocated Central Support Group Costs:									
10	**Strategy & Business Support[1,2]**	0.5	(0.1)	0.4	0.1	0.5	(0.0)	0.5	(0.4)	0.1
11	**Dam & Public Safety[2]**	0.1	(0.0)	0.1	0.0	0.1	(0.0)	0.1	(0.0)	0.1
12	**Environment[1]**	0.1	(0.0)	0.1	0.0	0.1	(0.0)	0.1	(0.1)	0.0
13	**Supply Chain[1]**	0.2	(0.0)	0.2	0.0	0.2	(0.0)	0.2	(0.2)	0.0
14	**Hydro-Thermal Project Execution[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Engineering & Technical Services[2]**	0.9	0.3	1.2	0.1	0.8	0.4	1.2	(0.3)	1.0
16	**SVP Office[2]**	0.1	(0.1)	0.1	0.0	0.2	(0.1)	0.1	(0.1)	0.0
17	**Total Allocated Central Support Costs**	2.0	0.0	2.0	0.3	1.9	0.3	2.3	(1.0)	1.2
18	**Total**	14.6	0.5	15.1	1.3	15.2	1.2	16.4	(1.7)	14.8

Line No.	Group	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Station:									
19	**Operations**	2.5	(0.2)	2.4	0.4	2.7	0.1	2.8	0.0	2.9
20	**Maintenance**	10.1	(0.3)	9.8	1.7	11.5	0.2	11.7	0.1	11.8
21	**Administration**	0.0	0.3	0.3	(0.1)	0.2	0.0	0.2	0.0	0.2
22	**Total Station**	12.6	(0.1)	12.5	1.9	14.5	0.2	14.7	0.2	14.9
23										
	Allocated Plant Group Common Costs:									
23	**Plant Group Management**	0.2	(0.0)	0.2	0.3	0.5	(0.0)	0.5	0.0	0.5
24	**Business Support**	0.1	(0.0)	0.1	(0.1)	0.0	0.0	0.0	0.0	0.0
25	**HR Support Services**	0.2	(0.0)	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0
26	**Asset Mgmt & Technical Support**	0.7	(0.2)	0.6	0.6	1.1	(0.0)	1.1	0.1	1.2
27	**Total Plant Group Allocated Costs**	1.2	(0.2)	1.0	0.6	1.6	(0.0)	1.6	0.1	1.6
28										
	Allocated Central Support Group Costs:									
28	**Strategy & Business Support[1,2]**	0.5	(0.4)	0.1	0.0	0.1	0.0	0.2	0.0	0.2
29	**Dam & Public Safety[2]**	0.1	(0.0)	0.1	0.0	0.1	0.0	0.1	0.0	0.1
30	**Environment[1]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Supply Chain[1]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Hydro-Thermal Project Execution[2]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Engineering & Technical Services[2]**	0.8	0.1	1.0	0.3	1.3	(0.0)	1.2	0.0	1.2
34	**SVP Office[2]**	0.2	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.1
35	**Total Allocated Central Support Costs**	2.0	(0.8)	1.2	0.3	1.6	0.0	1.6	0.1	1.6
36	**Total**	15.8	(1.1)	14.8	2.9	17.6	0.2	17.8	0.3	18.1

Notes:

1 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.

2 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

Table 5
Comparison of Base OM&A ($M)
Ottawa-St. Lawrence Plant Group[1]

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Budget[2]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Ottawa-St. Lawrence Plant Group[1]									
1	**Operations**	3.2	(0.1)	3.1	0.3	3.6	(0.2)	3.5	0.0	3.5
2	**Maintenance**	17.4	0.7	18.0	3.2	19.3	1.9	21.2	0.1	21.3
3	**Administration**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Total Plant Group**	20.6	0.6	21.2	3.5	23.0	1.7	24.7	0.1	24.8
	Allocated Plant Group Common Costs:									
5	**Plant Group Management**	0.3	0.0	0.4	(0.1)	0.3	(0.0)	0.3	0.0	0.3
6	**Business Support**	0.2	(0.1)	0.2	(0.1)	0.1	(0.0)	0.1	0.1	0.2
7	**HR Support Services**	0.3	0.0	0.3	0.0	0.3	(0.0)	0.3	(0.0)	0.3
8	**Asset Mgmt & Technical Support**	4.0	(0.4)	3.5	0.9	4.2	0.2	4.4	(0.6)	3.9
9	**Total Plant Group Allocated Costs**	4.8	(0.4)	4.4	0.8	5.1	0.2	5.2	(0.5)	4.7
	Allocated Central Support Group Costs:									
10	**Strategy & Business Support[4,5]**	1.0	(0.2)	0.8	0.4	1.3	(0.1)	1.2	(0.9)	0.3
11	**Dam & Public Safety[5]**	0.3	(0.0)	0.2	0.1	0.3	0.0	0.3	(0.0)	0.3
12	**Environment[4]**	0.3	(0.0)	0.2	0.0	0.3	(0.0)	0.3	(0.3)	0.0
13	**Supply Chain[4]**	0.2	(0.0)	0.1	(0.0)	0.1	0.0	0.1	(0.1)	0.0
14	**Hydro-Thermal Project Execution[5]**	0.1	(0.1)	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0
15	**Engineering & Technical Services[5]**	2.7	0.3	2.9	(0.6)	2.6	(0.2)	2.4	0.3	2.7
16	**SVP Office[5]**	0.3	(0.1)	0.2	0.0	0.3	(0.1)	0.2	(0.2)	0.1
17	**Total Allocated Central Support Costs**	4.8	(0.2)	4.6	(0.1)	4.9	(0.4)	4.5	(1.2)	3.3
18	**Total**	30.2	(0.0)	30.2	4.2	32.9	1.5	34.4	(1.6)	32.8

Line No.	Prescribed Facility	2012 Budget[2]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Ottawa-St. Lawrence Plant Group[1]									
19	**Operations**	3.6	(0.1)	3.5	0.3	3.8	0.1	3.9	0.1	4.0
20	**Maintenance**	20.8	0.5	21.3	4.1	25.4	0.2	25.7	(0.6)	25.0
21	**Administration**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Total Plant Group**	24.4	0.4	24.8	4.4	29.3	0.3	29.6	(0.6)	29.0
23										
	Allocated Plant Group Common Costs:									
23	**Plant Group Management**	0.4	(0.0)	0.3	0.6	0.9	(0.0)	0.9	(0.0)	0.9
24	**Business Support**	0.1	0.0	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0
25	**HR Support Services**	0.4	(0.1)	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0
26	**Asset Mgmt & Technical Support**	4.3	(0.4)	3.9	0.4	4.3	(0.2)	4.1	0.2	4.4
27	**Total Plant Group Allocated Costs**	5.1	(0.5)	4.7	0.5	5.2	(0.2)	5.0	0.2	5.2
28										
	Allocated Central Support Group Costs:									
28	**Strategy & Business Support[4,5]**	1.3	(1.1)	0.3	0.1	0.3	0.1	0.4	0.1	0.5
29	**Dam & Public Safety[5]**	0.3	(0.0)	0.3	0.0	0.3	0.0	0.3	0.0	0.3
30	**Environment[4]**	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	**Supply Chain[4]**	0.1	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	**Hydro-Thermal Project Execution[5]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	**Engineering & Technical Services[5]**	2.7	0.0	2.7	(0.2)	2.4	(0.1)	2.4	0.0	2.4
34	**SVP Office[5]**	0.2	(0.1)	0.1	0.0	0.1	0.0	0.1	0.0	0.1
35	**Total Allocated Central Support Costs**	4.9	(1.6)	3.3	(0.1)	3.2	0.0	3.2	0.2	3.4
36	**Total**	34.5	(1.7)	32.8	4.9	37.7	0.2	37.8	(0.2)	37.6

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.
2 As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.
3 As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.
4 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.
5 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

Numbers may not add due to rounding.

Table 6
Comparison of Base OM&A ($M)
Central Hydro Plant Group

Line No.	Prescribed Facility	2010 Budget[2]	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Budget[1]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Central Hydro Plant Group:									
1	**Operations**	1.7	(0.1)	1.6	0.6	2.0	0.3	2.2	(0.4)	1.9
2	**Maintenance**	11.7	0.0	11.7	0.7	13.2	(0.7)	12.5	0.2	12.7
3	**Administration**	5.5	(1.9)	3.6	1.7	6.1	(0.8)	5.2	(0.5)	4.8
4	**Total Plant Group**	18.9	(2.0)	16.9	3.0	21.2	(1.3)	19.9	(0.6)	19.3
	Allocated Central Support Group Costs:									
5	**Strategy & Business Support[3,4]**	0.7	(0.2)	0.5	0.2	0.9	(0.2)	0.7	(0.6)	0.2
6	**Dam & Public Safety[4]**	0.2	(0.0)	0.1	0.1	0.2	(0.0)	0.2	(0.0)	0.2
7	**Environment[3]**	0.2	(0.0)	0.1	0.0	0.2	(0.0)	0.2	(0.2)	0.0
8	**Supply Chain[3]**	0.1	0.0	0.1	(0.0)	0.2	(0.0)	0.1	(0.1)	0.0
9	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Engineering & Technical Services[4]**	1.2	(0.3)	0.9	0.2	1.3	(0.2)	1.1	0.3	1.4
11	**SVP Office[4]**	0.2	(0.1)	0.1	0.0	0.2	(0.1)	0.1	(0.1)	0.0
12	**Total Allocated Costs**	2.6	(0.6)	2.0	0.5	3.0	(0.5)	2.5	(0.7)	1.8
13	**Total**	21.5	(2.5)	18.9	3.5	24.3	(1.9)	22.4	(1.3)	21.1

Line No.	Prescribed Facility	2012 Budget[2]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Central Hydro Plant Group:									
14	**Operations**	2.1	(0.2)	1.9	0.5	2.3	0.0	2.4	0.1	2.4
15	**Maintenance**	13.8	(1.1)	12.7	2.6	15.3	(0.3)	15.0	0.2	15.1
16	**Administration**	6.0	(1.2)	4.8	0.3	5.1	(0.0)	5.0	0.2	5.2
17	**Total Plant Group**	21.9	(2.5)	19.3	3.4	22.7	(0.3)	22.4	0.4	22.8
	Allocated Central Support Group Costs:									
18	**Strategy & Business Support[3,4]**	0.7	(0.5)	0.2	0.0	0.2	0.1	0.3	0.1	0.3
19	**Dam & Public Safety[4]**	0.2	(0.0)	0.2	0.0	0.2	(0.0)	0.2	0.0	0.2
20	**Environment[3]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Supply Chain[3]**	0.1	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.1
23	**Engineering & Technical Services[4]**	1.2	0.2	1.4	(0.1)	1.3	(0.1)	1.2	0.0	1.2
24	**SVP Office[4]**	0.1	(0.1)	0.0	0.0	0.1	0.0	0.1	0.0	0.1
25	**Total Allocated Costs**	2.6	(0.9)	1.8	0.1	1.8	0.0	1.8	0.1	1.9
26	**Total**	24.5	(3.4)	21.1	3.4	24.5	(0.3)	24.2	0.5	24.7

Notes:

1. As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.
2. As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.
3. As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.
4. As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
   (1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
   (2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
   (3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
   (4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
   (5) the SVP Office was formerly the EVP Office.

Table 7
Comparison of Base OM&A ($M)
Northeast Plant Group

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Budget[1]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Northeast Plant Group:									
1	**Operations**	1.9	(0.2)	1.7	0.1	2.0	(0.2)	1.8	(0.1)	1.7
2	**Maintenance**	9.9	0.8	10.7	1.3	11.6	0.5	12.1	1.7	13.7
3	**Administration[1]**	4.7	(0.6)	4.1	0.6	5.1	(0.4)	4.7	0.0	4.7
4	**Total Plant Group**	16.5	(0.0)	16.5	2.1	18.7	(0.2)	18.5	1.6	20.2
	Allocated Central Support Group Costs:									
5	**Strategy & Business Support[3,4]**	0.7	(0.1)	0.5	0.2	0.8	(0.1)	0.7	(0.5)	0.2
6	**Dam & Public Safety[4]**	0.2	(0.0)	0.1	0.0	0.2	(0.0)	0.2	0.0	0.2
7	**Environment[3]**	0.2	(0.0)	0.1	0.0	0.2	(0.0)	0.2	(0.2)	0.0
8	**Supply Chain[3]**	0.2	0.0	0.3	(0.0)	0.3	(0.1)	0.2	(0.2)	0.0
9	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Engineering & Technical Services[4]**	1.4	(0.1)	1.3	(0.0)	1.3	0.0	1.3	(0.0)	1.3
11	**SVP Office[4]**	0.2	(0.1)	0.1	0.0	0.2	(0.1)	0.1	(0.1)	0.1
12	**Total Allocated Costs**	2.8	(0.3)	2.5	0.2	3.0	(0.2)	2.7	(1.0)	1.7
13	**Total**	19.3	(0.3)	19.0	2.3	21.7	(0.4)	21.3	0.6	21.9

Line No.	Prescribed Facility	2012 Budget[2]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Northeast Plant Group:									
14	**Operations**	1.9	(0.2)	1.7	0.4	2.1	(0.0)	2.1	(0.1)	2.0
15	**Maintenance**	14.3	(0.6)	13.7	1.0	14.8	(0.3)	14.4	0.2	14.7
16	**Administration[1]**	5.5	(0.8)	4.7	1.8	6.5	(0.9)	5.6	(0.4)	5.2
17	**Total Plant Group**	21.7	(1.5)	20.2	3.2	23.3	(1.2)	22.1	(0.2)	21.9
	Allocated Central Support Group Costs:									
18	**Strategy & Business Support[3,4]**	1.0	(0.8)	0.2	0.0	0.2	0.0	0.3	0.1	0.3
19	**Dam & Public Safety[4]**	0.2	(0.0)	0.2	0.0	0.2	(0.0)	0.2	0.0	0.2
20	**Environment[3]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Supply Chain[3]**	0.3	(0.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Engineering & Technical Services[4]**	1.2	0.1	1.3	(0.0)	1.3	(0.1)	1.2	(0.1)	1.1
24	**SVP Office[4]**	0.1	(0.1)	0.1	0.0	0.1	0.0	0.1	0.0	0.1
25	**Total Allocated Costs**	3.1	(1.3)	1.7	0.0	1.7	(0.0)	1.7	(0.0)	1.7
26	**Total**	24.8	(2.9)	21.9	3.2	25.1	(1.2)	23.8	(0.3)	23.6

Notes:

1 As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.

2 As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.

3 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.

4 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

Numbers may not add due to rounding.

Table 8
Comparison of Base OM&A ($M)
Northwest Plant Group

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Budget[1]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Northwest Plant Group:									
1	**Operations**	2.7	(0.3)	2.5	0.2	3.1	(0.4)	2.7	(0.1)	2.6
2	**Maintenance**	12.3	(0.8)	11.5	2.6	13.6	0.4	14.0	0.4	14.4
3	**Administration[1]**	3.9	10.9	14.8	(6.9)	4.4	3.4	7.9	(0.9)	6.9
4	**Total Plant Group**	18.9	9.8	28.7	(4.2)	21.1	3.4	24.6	(0.6)	24.0
	Allocated Central Support Group Costs:									
5	**Strategy & Business Support[3,4]**	0.8	0.0	0.8	(0.0)	1.0	(0.2)	0.8	(0.6)	0.2
6	**Dam & Public Safety[4]**	0.2	0.0	0.2	(0.0)	0.2	(0.0)	0.2	0.0	0.2
7	**Environment[3]**	0.2	0.0	0.2	(0.0)	0.2	(0.0)	0.2	(0.2)	0.0
8	**Supply Chain[3]**	0.4	(0.3)	0.1	0.0	0.2	(0.1)	0.1	(0.1)	0.0
9	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Engineering & Technical Services[4]**	2.0	(0.4)	1.6	0.3	1.8	0.0	1.8	0.9	2.7
11	**SVP Office[4]**	0.2	(0.1)	0.2	(0.0)	0.2	(0.1)	0.2	(0.1)	0.1
12	**Total Allocated Costs**	3.8	(0.7)	3.1	0.2	3.7	(0.4)	3.3	(0.1)	3.2
13	**Total**	22.7	9.2	31.8	(4.0)	24.9	3.0	27.9	(0.7)	27.2

Line No.	Prescribed Facility	2012 Budget[2]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Northwest Plant Group:									
14	**Operations**	3.4	(0.8)	2.6	0.8	3.4	0.1	3.5	(0.1)	3.3
15	**Maintenance**	13.6	0.8	14.4	0.4	14.8	1.4	16.2	0.3	16.5
16	**Administration[1]**	4.2	2.7	6.9	(2.4)	4.5	(0.1)	4.4	(0.0)	4.4
17	**Total Plant Group**	21.3	2.7	24.0	(1.3)	22.7	1.4	24.1	0.1	24.3
	Allocated Central Support Group Costs:									
18	**Strategy & Business Support[3,4]**	1.0	(0.8)	0.2	0.0	0.2	0.1	0.3	0.1	0.4
19	**Dam & Public Safety[4]**	0.2	0.0	0.2	(0.0)	0.2	0.0	0.2	0.0	0.2
20	**Environment[3]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Supply Chain[3]**	0.2	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	**Hydro-Thermal Project Execution[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Engineering & Technical Services[4]**	2.1	0.7	2.7	0.1	2.8	0.0	2.8	0.0	2.9
24	**SVP Office[4]**	0.1	(0.1)	0.1	(0.0)	0.1	0.0	0.1	0.0	0.1
25	**Total Allocated Costs**	3.8	(0.6)	3.2	0.1	3.3	0.1	3.4	0.1	3.6
26	**Total**	25.1	2.1	27.2	(1.2)	26.0	1.6	27.5	0.3	27.8

Notes:
1 As these assets were not regulated in EB-2010-0008, 2011 Budget is provided rather than 2011 Board Approved.
2 As these assets were not regulated in EB-2010-0008, 2012 Budget is provided rather than 2012 Board Approved.
3 As described in Ex. F1-2-1, starting in 2012, First Nations/Metis Relations (formerly Aboriginal Relations) and Water Resources are part of Corporate Allocations and not included with Business Support costs. Similarly, Environment and Supply Chain are also part of Corporate Allocations starting in 2012.
4 As described in Ex. F1-2-1, with the merger of the Hydroelectric and Thermal business units, a number of organizational changes have occurred, as follows:
(1) the Strategy & Business Support line item includes the former Business Support & Regulatory Affairs and Water Resources & Aboriginal Affairs, except as described in Note 1;
(2) Dam & Public Safety was formerly Dam Safety and Emergency Preparedness;
(3) Hydro-Thermal Project Execution includes the former Hydroelectric Development;
(4) the new Hydro-Thermal Engineering and Technical Services includes the former Hydroelectric Engineering Services; and
(5) the SVP Office was formerly the EVP Office.

PROJECT OM&A – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides a summary of the OM&A project expenses for the Niagara Plant Group and R.H. Saunders GS, and the newly regulated hydroelectric facilities.

2.0 OVERVIEW

A summary of the regulated hydroelectric project OM&A expenses for 2010 - 2015 is provided in Ex. F1-3-1 Table 1. The test period project OM&A expenses of $38.0M and $50.1M (in 2014 and 2015 respectively) form part of the OM&A expense in the revenue requirement.

The project expenses in 2014 and 2015 associated with the Niagara Plant Group and R.H. Saunders GS are $13.5M and $17.9M, and $24.5M and $32.1M for the newly regulated hydroelectric stations. Project OM&A can vary significantly from year to year based on the number and size of projects to be executed. Project OM&A expenses are increasing in the test period, as compared to 2013, due to the start of major unit overhauls at the Sir Adam Beck Pump Generating Station, Lower Notch GS and Otto Holden GS, in addition to, the R.H. Saunders GS Administration Building Envelope Rehabilitation, and the continuation of the Chats Falls Generating Station Main Dam Restoration.

OM&A projects differ from base OM&A work because they have a non-recurring scope of work, a generally longer timeline and a higher materiality threshold. In contrast, base OM&A work activities are typically of an ongoing or routine nature. OM&A projects are distinct from capital projects because they do not meet the criteria for capitalization under OPG's capitalization policy (see Ex. A2-2-1). Hydroelectric plant groups manage both capital and OM&A projects in a project listing that forms the basis for budgeting during the annual business planning process. Projects are identified through routine inspections, engineering reviews and detailed plant condition assessments. The process for identifying and prioritizing hydroelectric projects is described in Ex. F1-1-1.

OM&A projects are mainly sustaining expenditures for repairs and maintenance, such as major unit overhauls. The costs are above a materiality threshold (typically $100k) but do not meet the rules for capitalization. In addition to maintenance projects for production equipment, there are many projects related to aging civil structures. Project OM&A expenditures on production equipment includes the unit overhaul program at Sir Adam Beck Pump G.S., which is starting in 2013. This project is estimated at $21.3M, of which $8.6M is planned to be spent in 2014 and 2015. Other examples of expenditures on production equipment include the unit overhaul programs at Lower Notch GS and Otto Holden GS, which are estimated to be $48.1M, of which $16.3M is planned to be spent in 2014 and 2015. At the Ottawa St. Lawrence Plant Group, two projects are included which address aging infrastructure. The R.H. Saunders GS Administration Building Envelope Rehabilitation and the Chats Falls Generating Station Main Dam Restoration projects are estimated to cost $7.5M and $18.9M respectively, of which $4.0M and $7.5M is planned to be spent in 2014 and 2015.

Major OM&A projects are listed in Ex. F1-3-3. The management of hydroelectric OM&A projects is identical to that of capital projects as described in Ex. D1-1-1.

Table 1

Project OM&A - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	4.9	6.2	12.4	9.7	9.3	11.0
2	**Saunders GS**	0.4	0.4	1.2	3.3	4.2	7.0
3	**Subtotal**	5.4	6.6	13.6	13.0	13.5	17.9
	Newly Regulated Hydroelectric:						
4	**Ottawa-St.Lawrence Plant Group**[1]	10.6	8.5	12.0	8.1	9.0	19.0
5	**Central Hydro Plant Group**	3.1	4.1	1.2	2.1	4.2	4.0
6	**Northeast Plant Group**	10.9	2.6	1.9	3.0	7.8	6.0
7	**Northwest Plant Group**	15.2	6.5	5.3	2.8	3.5	3.2
8	**Subtotal**	39.8	21.6	20.3	16.0	24.5	32.1
9	**Total**	45.1	28.2	33.9	28.9	38.0	50.1

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

COMPARISON OF PROJECT OM&A - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of project OM&A for Niagara Plant Group and R.H. Saunders GS, and the newly regulated hydroelectric facilities.

2.0 PERIOD-OVER-PERIOD CHANGES

Year-over-year variances are presented by plant group in Ex. F1-3-2 Table 1 and by project category in Ex. F1-3-2 Table 2 and are explained here.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2015 Plan versus 2014 Plan

From 2014 - 2015, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures are expected to increase by $4.5M to a total plan of $17.9M. For the newly regulated hydroelectric, OM&A project expenditures are expected to increase by $7.6M to a total plan of $32.1M.

Niagara Plant Group

In 2015, Niagara Plant Group OM&A project expenditures are expected to increase by $1.7M to $11.0M due to planned expenditures for DeCew Falls II GS West Approach Bridge and Sir Adam Beck I GS Screenhouse Roof projects. These expenditures are partly offset by the completion of Sir Adam Beck I GS Elevator #1 Shaft and Exit Gallery project in 2014.

R.H. Saunders Generating Station

In 2015, R.H. Saunders GS OM&A project expenditures are expected to increase by $2.8M to $7.0M due to planned expenditures for various smaller projects and the Administration Building Envelope Rehabilitation. The Administration Building Envelope work consists of replacing the deteriorating east brick wall including windows and flashing. These incremental costs are partly offset by the completion of the Barnhardt Island Bridge (NYPA joint works) project in 2014.

Ottawa-St.Lawrence Plant Group

In 2015, Ottawa St. Lawrence Plant Group OM&A project expenditures are expected to increase by $10M to $19.0M due to planned expenditures on the Otto Holden GS Unit Overhauls, Calabogie GS Upstream Waterline Erosion Repair, Stewartville GS Tailrace Deck Repair projects, as well as a number of other smaller projects.

Central Hydro Plant Group

At Central Hydro Plant Group, project expenditures are $0.2M less in 2015 than 2014. The small decrease is due to a number of projects completing in 2014, including the Ranney Falls Bridge/Intake Structure and the South Falls G2 Turbine and Generator Replacement projects.

Northeast Plant Group

In 2015, Northeast Plant Group OM&A project expenditures are expected to decrease by $1.8M to $6.0M. This decrease is primarily due to the completion of geotechnical repairs (downstream slope stabilization) at the Frederick House Lake Control Dam upstream of Abitibi Canyon GS and Otter Rapids GS in 2014.

Northwest Plant Group

At Northwest Plant Group, project expenditures decrease by $0.4M to $3.2M in 2015 primarily due to the completion of the Whitedog Falls GS Headworks Concrete Rehabilitation in 2014.

Projects by Category

Regulatory projects planned for R.H. Saunders in 2015 decrease by $1.4M versus 2014 primarily as a result of the completion of the painting of the Barnhart Island Bridge (NYPA contractual) in 2014. Sustaining projects for R.H. Saunders increase by $4.1M in 2015 primarily due to the Administration Building Envelope Rehabilitation. In the Niagara Plant Group regulatory spending is expected to decrease $0.7M to zero while sustaining project expenditures will increase by $2.4M. The increase in sustaining project expenditures is mainly attributed to the Sir Adam Beck I Screenhouse Roof and the DeCew Falls II West Approach Bridge.

For the newly regulated hydroelectric, planned expenditures for regulatory projects increase by $2.0M to $2.2M and planned expenditures for sustaining projects increase by $5.6M to $29.9M in 2015. The increase in regulatory project spending is due to the start of the Northwest Plant Group Station Access Security Upgrade (public safety) and the Calabogie Upstream Waterline Erosion Repair (environmental). The increase in sustaining project spending is due to the start of the Lower Notch GS G2 Unit Overhaul in 2015.

2014 Plan versus 2013 Budget

From 2013 to 2014, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures are expected to increase by $0.5M to a total of $13.5M. For the newly regulated hydro, OM&A project expenditures are expected to increase by $8.6M to a total plan of $24.5M.

Niagara Plant Group

In 2014, Niagara Plant Group OM&A project expenditures are expected to decrease by $0.4M to $9.3M. This decrease is primarily due to the completion of the Waterworks Canal Levee Remediation and Sir Adam Beck I Powerhouse Roof Replacement projects. These decreases are partly offset by planned expenditures on Sir Adam Beck Pump Generating Station Units 1 – 5 Overhauls, and Sir Adam Beck I Elevator #1 Shaft and Exit Gallery project which is starting execution in 2014.

R.H. Saunders Generating Station

At R.H. Saunders, project expenditures increase by $0.9M to $4.2M in 2014. The small increase is due to a number of projects starting in 2014 and many continuing from 2013. The Barnhardt Island Bridge continues into 2014 with an increased scope of work. Also, in 2014, the R.H. Saunders GS Long Sault Dam North and South Gantry Crane painting project begins.

Ottawa-St.Lawrence Plant Group

In 2014, Ottawa St. Lawrence Plant Group OM&A project expenditures are expected to slightly increase by $0.9M to $9.0M due to timing of planned expenditures on a number of projects. The Des Joachims GS Elevator Replacement and the Otto Holden GS Unit Overhauls projects also begin in 2014.

Central Hydro Plant Group

In 2014, Central Hydro Plant Group OM&A project expenditures are expected to increase by $2.1M to $4.2M due to planned expenditures on the Ranney Falls GS Bridge/Intake Structures, South Falls GS G2 Turbine and Generator Replacement, and Lakefield GS and Tretheway Falls GS Turbine Overhauls projects.

Northeast Plant Group

In 2014, Northeast Plant Group OM&A project expenditures are expected to increase by $4.8M to $7.8M due to increased planned expenditures on the Lower Notch GS G1 Unit Overhaul project.

Northwest Plant Group

In 2014, Northwest Plant Group OM&A project expenditures are expected to slightly increase by $0.8M to $3.5M due to planned expenditures on the Whitedog Falls GS Headworks Concrete Rehabilitation project.

Projects by Category

Regulatory projects planned for R.H. Saunders increase slightly by $0.7M in 2014 versus 2013 which is a result of timing for NYPA (contractual) related projects including the painting of the Barnhart Island Bridge. Sustaining projects for R.H. Saunders increase by $0.2M in 2014 primarily as a result of ongoing minor project work. In the Niagara Plant Group, regulatory spending is expected to increase $0.5M while sustaining project expenditures will decrease by $1.0M. The regulatory increase is largely due to the advancement of the Sir Adam Beck Pump Generating Station Site Drainage Repairs (dam safety) in 2014. The decrease in sustaining project expenditures is mainly attributed to the completion of the DeCew Falls GS Waterworks Canal Levee Remediation project in 2013.

For the newly regulated hydroelectric, planned expenditures for regulatory projects decrease by $0.8M to $0.2M and planned expenditures for sustaining projects increase by $9.4M to $24.3M in 2014. The decrease in regulatory project spending is primarily due to the completion of the Abitibi Canyon GS Breaker Demerger Project (contractual) in 2013. The increase in sustaining project spending is due to the start of the Lower Notch GS G1 Unit Overhaul and the Frederickhouse Lake Dam Downstream Slope Stability projects in 2014.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget versus 2012 Actual

From 2012 - 2013, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures are expected to decrease by $0.6M to a total budget of $13.0M. For the newly regulated hydro, OM&A project expenditures are expected to decrease by $4.4M to a total budget of $16.0M.

<u>Niagara Plant Group</u>

In 2013, Niagara Plant Group OM&A project expenditures are expected to decrease by $2.7M to $9.7M due to lower planned expenditures on Sir Adam Beck II GS Headworks Deck Rehabiliation and Sir Adam Beck I GS Powerhouse Roof Replacement projects, and the completion of the Sir Adam Beck Switchyard Vehicle Bridge in 2012. These decreases are partly offset by Sir Adam Beck Pump Generating Station Units 1 – 5 Overhaul which is starting execution in 2013.

<u>R.H. Saunders Generating Station</u>

In 2013, R.H. Saunders planned increase for OM&A projects of $2.1M to $3.3M covers a number of civil and mechanical repair projects. The largest project is the start of the Barnhardt Island Bridge Painting by NYPA with $2.2M of costs planned for 2013.

Ottawa-St.Lawrence Plant Group

In 2013, Ottawa St. Lawrence Plant Group OM&A project expenditures are expected to decrease by $3.9M to $8.1M due to a significant reduction in the number of small projects in 2013 (approximately 10) compared to 2012 (approximately 40).

Central Hydro Plant Group

In 2013, Central Hydro Plant Group OM&A project expenditures are expected to increase by $1.0M to $2.1M due to planned expenditures on the Crystal Falls GS Concrete Rehabiliation project.

Northeast Plant Group

In 2013, Northeast Plant Group OM&A project expenditures are expected to increase by $1.0M to $3.0M due to planned expenditures on the Indian Chute GS Concrete and Grout Repairs project.

Northwest Plant Group

In 2013, Northwest Plant Group OM&A project expenditures are expected to decrease by $2.5M to $2.8M due to the completion of the Pine Portage GS Sluicegate Automation project and the $1.0M addition to the First Nation provision for the Whitesands Erosion project in 2012.

Projects by Category

Expenditures by project category show a $2.2M increase in 2013 for R.H. Saunders for regulatory projects due to the Barnhardt Island Bridge painting (NYPA contractual). Sustaining projects for R.H. Saunders decrease in 2013 by $0.1M primarily as a result of several smaller projects. In the Niagara Plant Group, regulatory spending is expected to decrease by $0.7M, while sustaining project expenditures will decrease by $2.0M. These decreases are largely due to the reduced expenditures for projects at the Sir Adam Beck stations as described above.

For the newly regulated hydroelectric, planned expenditures for regulatory projects decrease by $0.7M to $1.0M and planned expenditures for sustaining projects decrease by $3.7M to $15.0M in 2013. The decrease in regulatory project spending was primarily due to the transfer of the Whitesand First Nation Erosion Repairs (environmental/contractual) project in 2012 from a OM&A project to a Provision funded project. The decrease in sustaining project spending was due to the completion of the Matabichuan GS Concrete Repairs and Mountain Chute GS Overhauls projects in 2012.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual versus 2012 Board Approved

In 2012, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures were $13.6M, or $3.6M above the plan approved by the OEB in EB-2010-0008. For the newly regulated hydroelectric, OM&A project expenditures were $20.3M or $0.3M below the approved budget.

Niagara Plant Group

OM&A project spending for the Niagara Plant Group in 2012 was $12.4M, or $6.4M above the OEB approved plan of $6.0M. The increase in expenditures primarily results from the advancement of the Sir Adam Beck II GS Headworks Deck Rehabilitation and the Sir Adam Beck I GS Powerhouse Roof Replacement projects due to poor asset condition. In addition, new projects were identified after the completion of the previous rate application, including the Waterworks Canal Levee Remediation at DeCew Falls GS and the Switchyard Vehicle Bridge Overhaul at the Sir Adam Beck station, which contributed to the above plan spending. These increases were partially offset by the deferral of the major unit overhaul at the Sir Adam Beck Pump Generating Station, which is now planned to start in 2013.

R.H. Saunders Generating Station

The R.H. Saunders 2012 actual OM&A project spending was $1.2M or $2.8M below the OEB approved plan of $4.0M. This is primarily a result of deferral by NYPA of the painting of the Barnhardt Island Bridge to 2013/2014 ($3.4M), offset by the Oil Handling System removal being deferred from 2011 to 2012 at a revised cost of $0.4M.

Ottawa-St.Lawrence Plant Group

OM&A project spending for the Ottawa St. Lawrence Plant Group in 2012 was $12.0M, or $0.3M below budget. The variance was due to spending changes on numerous small projects.

Central Hydro Plant Group

In 2012, Central Hydro Plant Group 2012 OM&A project spending was mostly on the $1.2M budget. The Ragged Rapids GS G1 Overhaul actual project spending was more than planned due to a scope change which was partly offset by less than planned spending on the Coniston GS Turbine Overhaul concept study.

Northeast Plant Group

In 2012, Northeast Plant Group OM&A project spending was $0.8M less than the 2012 budget of $2.7M. The variance was due to the less than planned spending on concrete repairs at Matabitchuan GS, partly offset by the Indian Chute GS G2 Overhaul work which, due to construction delays, was carried over from a planned completion 2011 into 2012.

Northwest Plant Group

In 2012, Northwest OM&A project spending was $0.8M more than the 2012 budget of $4.5M. The addition of the $1.0M First Nation provision for the Whitesand Erosion project was offset by the deferral of Alexander GS Spillwall Rehabiliation project.

Projects by Category

In the Niagara Plant Group spending on regulatory projects is expected to remain stable when compared to the plan presented in EB-2010-0008, while sustaining project spending increased by $5.5M over the 2012 Plan larlgly due to the newly identified projects as described above. R.H Saunders spending on regulatory projects decreased by $3.0M and increased for sustaining projects by $0.6M in the 2012 budget versus the 2012 plan as a result of the two projects mentioned above.

For the newly regulated hydro, regulatory projects were $1.3M over budget and sustaining projects were $1.5M under budget. The increase in regulatory project spending was primarily due to the addition of the Northwest Plant Group First Nation provision changes as described above. The decrease in sustaining project spending was due to the less than planned spending on the Matabichuan GS Concrete Repairs and Des Joachims Turbine Overhauls.

2012 Actual versus 2011 Actual

From 2011 to 2012, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures increased by $7.0M to a total of $13.6M. For the newly regulated hydro, OM&A project expenditures decreased by $1.3M to a total plan of $20.3M.

Niagara Plant Group

In 2012, Niagara Plant Group OM&A project expenditures increased by $6.2M to $12.4M. This increase is primarily due to the start of construction work on Sir Adam Beck I GS powerhouse roof replacement, the rehabilitation of the headworks and tailrace decks at Sir Adam Beck II, the remediation of the Waterworks Canal at DeCew Falls GS, and the overhaul of the Sir Adam Beck switchyard vehicle bridge.

R.H. Saunders Generating Station

At R.H. Saunders, project expenditures increased by $0.8M to $1.2M more in 2012. The increase is due to numerous projects with minor spending changes, and the addition of a project for the removal of the old Oil Handling system in 2012.

Ottawa-St.Lawrence Plant Group

In 2012, Ottawa St. Lawrence Plant Group OM&A project expenditures increased by $3.5M to $12.0M mainly due to the start of the Chat Falls GS Main Dam Concrete Restoration in 2012.

Central Hydro Plant Group

In 2012, Central Hydro Plant Group OM&A project expenditures decreased by $3.0M to $1.2M due to completion of the Elliott Chute GS Intake Concrete Repairs, the Northbury and

Gravenhurst Service Centre Public Safety Upgrades, Seymour GS Turbine Overhauls, and significant completion of Trethewey GS Gain Replacement in 2011.

Northeast Plant Group

In 2012, Northeast Plant Group OM&A project expenditures decreased by $0.7M to $1.9M due to additional unplanned work in 2011 to repair cracks discovered on the Abitibi Canyon GS Unit 2 turbine runner.

Northwest Plant Group

In 2012, Northwest Plant Group OM&A project expenditures decreased by $1.2M to $5.3M, primarily due to the completion of the Manitou Falls GS Pier and Curtain Wall Repair project in 2011.

Projects by Category

In the Niagara Plant Group regulatory spending decreased from $1.1M in 2011 to $0.8M in 2012. This decrease is primarily due to the completion of the Niagara Queen II ice breaker overhaul in 2011. Sustaining expenditures increased from $5.1M in 2011 to $11.5M in 2012. This increase is due to increased spending on the powerhouse roof replacement at Sir Adam Beck I, rehabilitation of the headworks and tailrace decks and the switchyard bridge at Sir Adam Beck II and the remediation of the waterworks canal levee at DeCew Falls GS. R.H. Saunders expenditures by project category were relatively stable for regulatory (contractual) projects while sustaining projects show increased due to the Removal of Oil handling system and tanks project planned for 2012.

For the newly regulated hydro, regulatory projects decreased by $2.2M to $1.7M and sustaining projects increased by $0.9M to $18.7M in 2012. The decrease in regulatory project spending was primarily due to the completion of the Bark Lake Control Dam Concrete Rehabilitation in 2011. Sustaining projects were largely unchanged.

2011 Actual versus 2011 Board Approved

For 2011, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures were $6.6M or $3.1M below budget. For the newly regulated hydro, OM&A project expenditures were $21.6M or $5.7M under budget.

Niagara Plant Group

For the Niagara Plant Group, OM&A project costs were $0.5M below budget. The variance was mainly due to the deferral of the tunnel intake gate overhaul ($0.8M), definition phase work for the major unit overhauls at Sir Adam Beck PGS ($0.4M), and the cancellation of trashrack overhauls at Sir Adam Beck II GS ($0.6M) and main elevator assessment work at Sir Adam Beck I GS ($0.7M). These reductions were offset by increased expenditures on other projects such as the concrete restoration work at Sir Adam Beck I screen house ($0.3M), and new projects that were added to the work program such as Niagara Queen ice breaker regulatory overhaul ($0.7M) and Sir Adam Beck II disconnect switch replacement ($0.9M).

R.H. Saunders Generating Station

The R.H. Saunders 2011 actual spending was $0.4M versus the Board approved plan of $3.0M, or $2.6M under budget. The less than planned spending was mainly due to deferral of the Ice Sluices and Steel Support Beams Repairs from 2011 to 2016, the Painting of the Long Sault Dam Cranes from 2011 to 2014 by NYPA, the start of the Barnhardt Island Bridge Painting project from 2011 to 2013 by NYPA, and the Main Dam Foundation Drainage Cleaning to 2016 as per the recommendations of a technical assessment.

Ottawa-St.Lawrence Plant Group

The Ottawa St. Lawrence 2011 actual spending was $8.5M versus the budget of $15.3M, or $6.8M under budget. This was due to a number of projects being budgeted for but not started due to resourcing issues resulting in a delay of project releases. In particular, there was a scope change to the Chat Falls GS Main Dam Concrete Restoration and less than planned spending on the Bark Lake Control Dam Concrete Rehabilitation. The scope of work identified for the Chats Falls GS Main Dam Concrete Restoration was significantly more than estimated. As a result, more engineering was required and the project execution was deferred to 2012. The Bark Lake Control Dam Rehabilitation had less than plan spending in 2011 due to much less contingency required than planned.

Central Hydro Plant Group

For the Central Hydro Plant Group, OM&A project costs were $0.6M over the 2011 budget of $3.5M. This is primarily due to unanticipated civil repairs at Tretheway Falls GS. This discovery work was identified during the commissioning of the log lifter, and the repairs were required to maintain reliable operation of flow control equipment.

Northeast Plant Group

For the Northeast Plant Group, OM&A project costs were $0.7M over the 2011 budget of $1.8M. This increase was primarily due to the discovery of cracks on the Abitibi Canyon GS Unit 2 turbine runner.

Northwest Plant Group

For the Northwest Plant Group, 2011 actual OM&A project costs were $0.3M under the 2011 budget of $6.7M which can be attributed to the reclassification of the Pine Portage GS Plant Lighting Upgrade from an OM&A project to Capital. The largest project in 2011, the Manitou Falls GS Headworks Concrete Repair at $3.8M was delivered on budget.

Projects by Category

Niagara Plant Group regulatory expenditures were on budget at $0.7M, while spending on sustaining projects in 2011 were only $0.5M below the budget of $5.8M due to the deferral of the overhauls projects described above. R.H. Saunders regulatory projects were below budget due to the deferral of the two NYPA joint works painting projects described above. Sustaining projects were below budget due the deferral of ice sluice and drainage cleaning projects described above.

For the newly regulated hydro, regulatory projects were $1.7M under budget and sustaining projects were $4.0M under budget. The decrease in regulatory project spending was primarily due to less than planned spending on the Bark Lake Control Dam Concrete Rehabilitation. The decrease in sustaining project spending was primarily due to a number of projects being budgeted for but not started, and a scope change to the Chat Falls GS Main Dam Concrete Restoration.

2011 Actual versus 2010 Actual

From 2010 to 2011, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures increased by $1.3M to a total of $6.6M. For the newly regulated hydro, OM&A project expenditures decreased by $18.2M to a total plan of $21.6M.

Niagara Plant Group

Niagara Plant Group's increase of $1.3M to $6.2M in 2011 was due to the start of construction for concrete restoration of the Sir Adam Beck I screenhouse.

R.H. Saunders Generating Station

There was no change in OM&A project spending of $0.3M at R.H. Saunders from 2010 to 2011.

Ottawa-St.Lawrence Plant Group

In 2011, Ottawa St. Lawrence Plant Group OM&A project expenditures decreased by $2.1M to $8.5M. This decrease was primarily due to the completion of the Stewartville GS Main Dam Upper Deck Concrete Rehabilitation and the Otto Holden GS Window Replacement projects in 2010.

Central Hydro Plant Group

In 2011, Central Hydro Plant Group OM&A project expenditures increased by $1.0M to $4.1M. This increase was primarily due to the start of the Elliot Chute GS Intake Concrete Repairs project in 2011.

Northeast Plant Group

In 2011, Northeast Plant Group OM&A project expenditures decreased by $8.3M to $2.6M. This decrease was primarily due to the completion of the Abitibi Canyon GS Tailrace Pier Rehabilitation in 2010 and deferral of a unit overhaul at Lower Notch GS to allow for further testing to better determine the project scope.

Northwest Plant Group

From 2010 - 2011, Northwest Plant Group OM&A project expenditures decreased by $8.8M to $6.5M due primarily to the First Nation provision changes in 2011 of $4.0M compared to 2010 of $11.3M. The balance can be attributed to completion of a number of concrete restoration projects completed at Pine Portage, Ear Falls and Whitedog Falls GSs.

Projects by Category

Expenditures by project category show only a small increase in in sustaining projects due to the Sir Adam Beck I screen house concrete restoration project described above. Niagara Plant Group regulatory expenditures increased due to increased spending on the Niagara Queen II icebreaker overhaul.

For the newly regulated hydro, regulatory projects decreased by $9.4M to $3.9M and sustaining projects decreased by $8.8M to $17.7M in 2011. The decrease in regulatory project spending was primarily due to the Northwest Plant Group's First Nation provision changes as described above. The decrease in sustaining project spending was primarily due to the completion of the Abitibi Canyon GS Tailrace Pier Rehabilitation project in 2010.

2010 Actual versus 2010 Budget

For 2010, Niagara Plant Group and R.H. Saunders GS OM&A project expenditures were $5.4M or $0.1M higher than budget. For the newly regulated hydro, OM&A project expenditures were $39.8M or $2.7M over budget.

Niagara Plant Group

Niagara Plant Group OM&A project spending in 2010 was $0.9M higher than budget. This higher than expected spending in 2010 resulted from increased spending on the powerhouse concrete restoration ($0.8M) and work on the main elevator ($0.8M) at Sir Adam Beck I, dyke protective measures at Sir Adam Beck PGS ($0.3M) and a number of smaller projects. These increases were partially offset by the deferral of road repairs at Sir Adam Beck I ($0.4M) and tunnel intake gate overhaul ($0.3M) and through the cancellation of parkway wall repairs at Sir Adam Beck I ($0.5M) and trashrack repairs at Sir Adam Beck II ($0.4M).

R.H. Saunders Generating Station

R.H. Saunders' OM&A project spending in 2010 was $0.8M below budget as a result of the lower than expected contingency required for the Underwater Dam Inspection at Long Sault Dam (NYPA JW), the Uplift Pressure Cells Replacement on the Long Sault Dam was deemed unnecessary by NYPA, and some other minor project cash flow changes on several projects.

Ottawa-St.Lawrence Plant Group

The Ottawa St. Lawrence 2010 actual spending was $10.6M versus the budget of $12.7M, or $2.2M under budget. This is primarily due to less than planned spending on the Bark Lake Control Dam Concrete Rehabilitation and Mountain Chute GS Unit Overhauls. A portion of scope for the Bark Lake Control Dam Rehabilitation project was determined to be capital in nature and was therefore reclassified as a capital project. Work originally planned for the Mountain Chute GS, Unit 2 Overhaul was deferred to 2011 to reassess the execution approach to line up with the Capital Rewind Project.

Central Hydro Plant Group

For the Central Hydro Plant Group, OM&A project costs were $2.2M under the 2010 budget of $5.3M. This is primarily due to the deferral of the Ragged Rapids GS G1 Overhaul project to allow further investigation of the project scope and cost to 2011.

Northeast Plant Group

For the Northeast Plant Group, OM&A project costs were $0.1M under the 2010 budget of $10.9M. This is primarily due to less than planned spending on a number of small OM&A projects. The Abitibi Canyon Tailrace Pier Rehabilitation project was valued at $9.4M and was completed on budget in 2010.

Northwest Plant Group

The Northwest Plant Group 2010 actual spending was $15.2M versus the budget of $8.2M, or $7.0M over budget. This increase was due primarily to the addition of $7.5M First Nation provision for the Whitesand and Gull Bay Erosion projects. The $0.5M balance can be attributed to the cancellation of the Pine Portage Tailrace Pier Repair project.

Projects by Category

For expenditures by project category, regulatory projects were $0.6M below budget while sustaining projects were $0.7M above budget for 2010. Regulatory projects were below budget due to the deferral or cancellation of a number of bridge repair projects in the Niagara Plant Group. Sustaining project expenditures were $0.8M over the budget of $4.1M. This variance is due to higher than expected spending on concrete restoration work on Sir Adam Beck I powerhouse. For Project expenditures by category at R.H. Saunders, regulatory projects were under spent by $0.8M due to less spending by NYPA than planned.

For the newly regulated hydro, regulatory projects were $6.7M above budget while sustaining projects were $4.1M below budget. The increase in regulatory project spending was primarily due to the Northwest Plant Group’s First Nation provision changes as described above. The decrease in sustaining project spending was primarily due to lower than planned spending on the Mountain Chute GS Unit Overhauls project as described above.

Numbers may not add due to rounding.

Table 1

Comparison of Project OM&A - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved[2]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Niagara Plant Group**	4.0	0.9	4.9	1.3	6.7	(0.5)	6.2	6.2	12.4
2	**Saunders GS**	1.2	(0.8)	0.4	0.0	3.0	(2.5)	0.4	0.8	1.2
3	**Subtotal**	5.3	0.1	5.4	1.3	9.7	(3.1)	6.6	7.0	13.6
	Newly Regulated Hydroelectric:									
4	**Ottawa-St.Lawrence Plant Group[1]**	12.7	(2.2)	10.6	(2.1)	15.3	(6.8)	8.5	3.5	12.0
5	**Central Hydro Plant Group**	5.3	(2.2)	3.1	1.0	3.5	0.6	4.1	(3.0)	1.2
6	**Northeast Plant Group**	10.9	(0.1)	10.9	(8.3)	1.8	0.7	2.6	(0.7)	1.9
7	**Northwest Plant Group**	8.2	7.0	15.2	(8.8)	6.7	(0.3)	6.5	(1.2)	5.3
8	**Subtotal**	37.1	2.7	39.8	(18.2)	27.3	(5.7)	21.6	(1.3)	20.3
9	**Total**	42.4	2.8	45.1	(16.9)	37.0	(8.8)	28.2	5.7	33.9

Line No.	Prescribed Facility	2012 Board Approved[3]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
10	**Niagara Plant Group**	6.0	6.4	12.4	(2.7)	9.7	(0.4)	9.3	1.7	11.0
11	**Saunders GS**	4.0	(2.8)	1.2	2.1	3.3	0.9	4.2	2.8	7.0
12	**Subtotal**	10.0	3.6	13.6	(0.6)	13.0	0.5	13.5	4.5	17.9
	Newly Regulated Hydroelectric:									
13	**Ottawa-St.Lawrence Plant Group[1]**	12.2	(0.3)	12.0	(3.9)	8.1	0.9	9.0	10.0	19.0
14	**Central Hydro Plant Group**	1.2	(0.1)	1.2	1.0	2.1	2.1	4.2	(0.2)	4.0
15	**Northeast Plant Group**	2.7	(0.8)	1.9	1.0	3.0	4.8	7.8	(1.8)	6.0
16	**Northwest Plant Group**	4.5	0.8	5.3	(2.5)	2.8	0.8	3.5	(0.4)	3.2
17	**Subtotal**	20.6	(0.3)	20.3	(4.4)	16.0	8.6	24.5	7.6	32.1
18	**Total**	30.6	3.3	33.9	(5.0)	28.9	9.1	38.0	12.1	50.1

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

2 For Newly Regulated Hydroelectric, 2011 Budget is provided rather than 2011 Board Approved, as these assets were not regulated in EB-2010-0008.

3 For Newly Regulated Hydroelectric, 2012 Budget is provided rather than 2012 Board Approved, as these assets were not regulated in EB-2010-0008.

Numbers may not add due to rounding.

Table 2

Comparison of Project OM&A by Category - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Category	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved[1]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Regulatory**	1.2	(0.6)	0.5	1.0	1.3	0.2	1.5	(0.3)	1.2
2	**Sustaining**	4.1	0.7	4.8	0.3	8.4	(3.3)	5.1	7.2	12.3
3	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**Subtotal**	5.3	0.1	5.4	1.3	9.7	(3.1)	6.6	6.9	13.6
	Newly Regulated Hydroelectric:									
5	**Regulatory**	6.5	6.7	13.3	(9.4)	5.6	(1.7)	3.9	(2.2)	1.7
6	**Sustaining**	30.6	(4.1)	26.5	(8.8)	21.7	(4.0)	17.7	0.9	18.7
7	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Subtotal**	37.1	2.7	39.8	(18.2)	27.3	(5.7)	21.6	(1.3)	20.3
9	**Total**	42.4	2.8	45.1	(16.9)	37.0	(8.8)	28.2	5.7	33.9

Line No.	Category	2012 Board Approved[2]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
10	**Regulatory**	3.7	(2.5)	1.2	1.5	2.8	1.2	4.0	(2.1)	1.9
11	**Sustaining**	6.3	6.1	12.3	(2.1)	10.2	(0.7)	9.5	6.5	16.0
12	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Subtotal**	10.0	3.6	13.6	(0.6)	13.0	0.5	13.5	4.5	17.9
	Newly Regulated Hydroelectric:									
14	**Regulatory**	0.4	1.3	1.7	(0.7)	1.0	(0.8)	0.2	2.0	2.2
15	**Sustaining**	20.2	(1.5)	18.7	(3.7)	15.0	9.4	24.3	5.6	29.9
16	**Value Enhancing/Strategic**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Subtotal**	20.6	(0.3)	20.3	(4.4)	16.0	8.6	24.5	7.6	32.1
18	**Total**	30.6	3.3	33.9	(5.0)	28.9	9.1	38.0	12.1	50.1

Notes:
1 For Newly Regulated Hydroelectric, 2011 Budget is provided rather than 2011 Board Approved, as these assets were not regulated in EB-2010-0008.
2 For Newly Regulated Hydroelectric, 2012 Budget is provided rather than 2012 Board Approved, as these assets were not regulated in EB-2010-0008.

DETAILS OF OM&A PROJECTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to identify OM&A projects and provide available business case summaries for Tier 1 OM&A projects at OPG's regulated hydroelectric facilities.

2.0 OVERVIEW

OM&A projects are categorized as either Tier 1, Tier 2 or Tier 3. More specifically:

- Tier 1 OM&A projects have a total cost of $20M or greater that have budgeted expenditures during the test period. Business case summaries are provided, if available, for Tier 1 OM&A projects.
- Tier 2 projects have a total cost of $5M to $20M.
- Tier 3 projects have a total cost of less than $5M.

3.0 OM&A PROJECT DESCRIPTIONS

3.1 Tier 1 OM&A Projects

Tier 1 OM&A projects are those with total costs greater than or equal to $20M. There are three Tier 1 OM&A projects at OPG's regulated hydroelectric facilities that have planned expenditures during the test period – one at Niagara Plant Group and two at Ottawa St. Lawrence Plant Group (Ex. F1-3-3, Table 1). The costs of all regulated hydroelectric Tier 1 OM&A projects totals $77.8M - $21.3M at Niagara Plant Group and $56.5M at Ottawa St. Lawrence Plant Group (Ex. F1-3-3, Table 1). A detailed description of the projects follows.

3.1.1 <u>Niagara Plant Group: Sir Adam Beck, Pump Generating Station - Units 1 to 5 Overhauls (SABP0036)</u>

OPG intends to overhaul Units 1 to 5 at the Beck Pump Generating Station ("PGS"). The project cost was estimated at $21.3M for business planning purposes with a scheduled start in 2013. Subsequent to the approval of the current Business Plan, a decision was made to execute a partial release on the overhaul program for the first unit (i.e., PG3) to minimize schedule and estimate uncertainty associated with releasing a five unit overhaul program. A Business Case Summary was prepared for the PG3 overhaul and released under a different project number (SABP0053) (See Attachment 1). The Business Case included a capital acquisition of a spare set of turbine blades to ensure that replacement blades would be available for the unit overhaul program.

A unit overhaul program at the PGS was last completed in the mid to late 1990s. There was an expectation, at that time, that after completing these overhauls the runner life of these units would be 25 to 30 years. This period is consistent with the life expectancies of the Francis type runners at OPG's other generating stations and was consistent with the previous unit's service life at the PGS. However, since the unit overhauls were completed, the number of reversing operations and/or loading changes that the PGS units have experienced has increased significantly. The number of cycles is expected to further increase in response to changes in the Ontario generation mix and electricity system operation.

Additionally, in 2008, the seals on the PG6 runner failed after approximately ten years of service necessitating an emergency unit overhaul. Based on a careful inspection of the condition of the PG6 runner internal mechanisms, OPG has concluded that 15 years is a more reasonable service life expectation, given the complicated nature of the runner and the increased operations described above. Inspection of the runner blades also indicated that there is significant blade deformation. Correcting the blade deformation of the remaining units may increase unit efficiency and energy production.

Unit overhauls will begin with units PG3 and PG5. These units were overhauled at the start of the last overhaul program in the 1990's and currently have the greatest risk of failure. The results from the inspection of runner internal mechanisms during these overhauls will be used to confirm the 15-year life expectancy of these runners and to justify the overhauls on units PG1, PG2 and PG4. The first unit overhaul (PG3) is planned for 2014 and the second unit overhaul (PG5) is planned for 2015.

This project has been deferred by two years since it was identified in EB-2010-0008. This deferral is primarily due to the identification of the project for the capital replacement of the turbine runner blades at Sir Adam Beck PGS. Additional time was required to investigate the runner replacement which included detailed analysis of the existing runner blades and design optimization to ensure that runner blades are replaced with the most efficient blades practical.

3.1.2 Ottawa St. Lawrence Plant Group - Otto Holden Generating Station - Units 1 to 8 Overhauls (OTTO0036)

Since the early 1970's, Otto Holden GS has experienced structural and operation problems as a result of concrete growth associated with alkali-aggregate reactivity. Some of these problems include the reduction in runner clearances, misalignment of the turbine/generator assembly, and the seizing of the guide vanes in their bushings. A concrete growth mitigation project was executed between 1998 and 2008 and the concrete growth rate in the station is being tracked and critical clearances are being measured regularly. Unit overhauls are necessary to re-establish functional features and dimensional tolerances to ensure proper performance. In addition, future plans for mitigating the impact of concrete growth on unit performance will also be determined.

The recommended alternative is to execute one unit overhaul per year beginning in 2015. This project will reverse any current operating issues with the units, as well as mitigate the future risks to unit performance and reliability resulting from continued concrete growth. The Otto Holden GS Mechanical and Electrical Overhauls project is not released and therefore does not have a Business Case Summary.

3.1.3 Ottawa St. Lawrence Plant Group Chats Falls Generating Station Main Dam Restoration. (CHAF0035)

The Main Dam at Chats Falls GS was constructed in 1930 -1931 and is 5.24 km in length. The dam is divided into 13 sections or divisions for construction and identification purposes. These structures are currently experiencing significant deterioration leading to operational problems and potential structural and stability issues. Structural and weathering related deterioration has been observed and monitored since the 1940s. External engineering services were retained to carry out assessment inspections which also revealed the presence of alkali-aggregate reactivity which has contributed to the deterioration as well.

The project consists of the complete rehabilitation of all dam sections including all four stop log sluiceways and replacement of handrails. This work will mitigate operational risks associated with the deteriorating concrete, extend the service life of the structures, and reduce leakage and further concrete deterioration. This project was released in 2012 for a net cost of $20M (See Attachment 1). Hydro Quebec and Ontario Power Generation are sharing the gross $40M cost equally.

3.2 Tier 2 OM&A Projects

Tier 2 OM&A projects are those with total costs between $5M and $20M. There are sixteen Tier 2 OM&A projects at OPG's regulated hydroelectric facilities that have planned expenditures during the test period – one at Niagara Plant Group, three at R.H. Saunders GS, ten at Ottawa St. Lawrence Plant Group and two at Northeast Plant Group (Ex. F1-3-3, Table 2). The costs of all regulated hydroelectric Tier 2 OM&A projects totals $144.3M - $17.6M at Niagara Plant Group, $31.4M at R.H. Saunders GS, $83.7M at Ottawa St. Lawrence Plant Group and $11.6M at Northeast Plant Group (Ex. F1-3-3, Table 2).

3.3 Tier 3 OM&A Projects

Tier 3 OM&A projects are those with total costs less than $5M. There are 106 Tier 3 OM&A projects at OPG's regulated hydroelectric facilities that have planned expenditures during the test period – 23 at Niagara Plant Group, 13 at R.H. Saunders GS, 24 at Ottawa St. Lawrence Plant Group, 18 at Central Hydro Plant Group, 3 at Northeast Plant Group and 25 at Northwest Plant Group (Ex. F1-3-3, Table 3). The costs of all regulated hydroelectric Tier 3 OM&A projects totals $95.7M – $20.9M at Niagara Plant Group, $15.0M at R.H. Saunders GS, $26.8M at Ottawa St. Lawrence Plant Group, $16.1M at Central Hydro Plant Group, $3.1M at Northeast Plant Group and $13.8M at Northwest Plant Group (Ex. F1-3-3, Table 3).

LIST OF ATTACHMENTS

Attachment 1: Business Case Summaries

ATTACHMENT 1

Business Case Summaries

Provided below is a list of projects with total project cost of $20M or greater, and their associated business case summaries. Paper copies of the business case summaries are provided in a separate binder (EB-2013-0321 Volume 4).

Tab	Business Case Summaries	Project No.
1	Chats Falls GS - Main Dam Concrete Restoration	CHAF0035
2	Sir Adam Beck Pump GS – Unit Overhauls	SABP0053 (formerly SABP0036)

ONTARIO POWER GENERATION	**Project Number:** CHAF0035	**Facility:** Chats Falls GS	**Page:** 1 of 12 Rev. 00
	BUSINESS CASE SUMMARY Main Dam Concrete Rehabilitation		

1. RECOMMENDATION

Approve this full release of $40M to perform the rehabilitation of the concrete main dam, stop log sluices, at Chats Falls Generating Station, with 50% of the costs recoverable from Hydro Québec. This rehabilitation project will address existing concrete deterioration, operational problems with the stop log sluices, and emerging dam and personnel safety concerns. The project will be completed over a 5 year period to accommodate Ministry of Natural Resources (MNR) restrictions, and the historical flow and spill conditions (ie, minimize production losses).

Total Investment Cost: *$40M Gross (includes $180k Developmental Release funding - $162k spent to date as of end of 2011. 50% of these costs are to be recovered from Hydro Québec)*

	2011 LTD	2012	2013	2014	2015	2016	Total
Project Cashflows Gross cash flows ($M)	0.2	7.4	8.3	8.4	8.2	7.5	40
Project Cashflows Net cash flows ($M)	0.1	3.7	4.2	4.2	4.1	3.8	20
2012 Final Budget Version OPG share ($M)	0.1	2.5	2.5	2.0	2.0	2.0	11

Expenditure Type: Non-Standard
Investment Type: Sustaining – Maintain Condition Non-Production
Release Type: Full release under OAR element 1.1

Funding: The 2012 Business Plan includes funds for project execution in years 2012 - 2016. Additional scope items were identified during the definition phase activities and the RFP fixed price proposals were not received until after the finalization of the 2012-2016 Business Plan. The increased 2012 cash flows will be managed within the 2012 OSPG Non-Standard envelope, and future years (2013-2016) will be re-programmed in the 2013-2015 Business Plan. The 2001/2008 Chats Falls PCAs and 2001 Life Cycle Plan include this work.

Investment Financial Measures: The Present Value (PV) of the total costs related to this project is ($25.2M).

2. SIGNATURES

Submitted by:

Feb 14/12
Jim Moreland — Date
OSPG Plant Group Manager

Recommended by:

Feb 17, 2012
Frank Chiarotto — Date
Senior Vice-President, Hydro-Thermal

Finance Approval:

Feb 22/12
Donn Hanbidge — Date
SVP & Chief Financial Officer

Line Approval Per OAR:

4 May 12
Tom Mitchell — Date
President & Chief Executive Officer

3. BACKGROUND & ISSUES

Station Description:

Chats Falls GS is located on the Ottawa River, 56 km northwest of Ottawa. The station was built in 1931 and has 8 units with an installed capacity of 192 MW. The plant is owned jointly by Ontario Power Generation and Hydro Québec. Energy production from the facility is shared equally by both entities and investments are reimbursed by Hydro Québec on a project-by-project basis as per the OPG/Hydro Québec Operating Services Agreement. In 2011, OPG's revenue was $24M based on half of the total energy production of 562 GWh. Chats Falls is considered a "Middle-of-the-Pack" asset in OPG Hydroelectric portfolio. Planned investment over the next ten years represent approximately $37M (OPG costs), with the major projects including: main dam concrete restoration, replacement of the A/C station service, restoration of the generator rotor field poles, excitation system replacement and multiple repairs on the powerhouse building, etc. The NPV for the OPG owned half of the station, including the costs of the preferred alternative, is $263M. This project secures the ongoing profitability of the station to OPG and Hydro-Québec.

Background and Issues (Refer to Appendix A for site layout):

The dam is divided into thirteen sections (also called divisions) for construction and identification purposes (see site layout in Appendix A). It was constructed in 1930-1931 using natural sand and coarse crushed rock aggregate and is 5.24km long and spans across the Ontario-Québec border by approximately 2.5km onto the Quebec side. The main dam includes four sluiceways and more than 4.5km of concrete gravity sections. The four sluiceway structures (Victoria Island, Ragged Chute, Wolverine Chute and Merrill Island) total 74 stop log sluices, with 42 in Québec and 32 in Ontario, and a sluiceway that has four automated gates.

The structures are currently experiencing significant deterioration leading to operational problems and potential structural, stability, and personnel safety issues. Structural and weathering-related deterioration of the dams and sluiceways has been observed and monitored since the 1940's. External engineering services were retained by Ontario Power Generation to review available information, carry out assessment inspections and prepare a complete scope and technical specification. A previous assessment also identified the presence of Alkali-Aggregate Reactivity (AAR) which has contributed to the concrete deterioration. A definition phase was completed with the objective to ensure that maximum life span would be attained while minimizing the investment costs for both OPG & Hydro Québec and extend the service life of the dam for an additional 40 years.

The powerhouse as well as the sluice gate adjacent to it is not included in the work, with the exception of the replacement of the handrails and minor concrete work on the Powerhouse headworks (Division 6). Three of four main sluice gates were recently replaced with the final gate to be completed in 2012.

This project will restore the dam structures and associated equipment to address existing deterioration, operational problems, and emerging dam and personnel safety concerns. The project will be completed over a 5 year period to accommodate Ministry of Natural Resources (MNR) restrictions, and the historical flow and spill conditions (ie, minimize production losses).

Summary of the current major problems

The main issues are as follows:

- There is extensive leakage and deterioration in various sections of the main gravity dam which is rated as poor (per dam safety criteria). Sealing of the joints/cracks and repairs to these sections is needed to ensure continued stability of the dam.
- The leakage should be repaired in the near future to prevent more extensive deterioration and increased rehabilitation costs in the future.
- The sluiceway decks and dam crest have significant damage including spalled and cracked concrete leading structural problems and inadequate hand rail anchoring. Two cracked sluiceway decks and end piers are "tilted" inwards limiting the removal and installation of stop log.
- The handrails are deteriorated and non-compliant with current building codes.

Further details are provided below.

Structural and Operational Issues

1. Gravity sections

The gravity sections at Chats Falls GS have extensive deterioration which has been exacerbated by concrete growth (Alkali-Aggregate Reactivity). Some sections will require extensive repairs to maintain the structural integrity and prevent potential problems such as dam failure and uncontrolled leakage.

Divisions #5 and #9 have major stress cracks and are leaking. The Division #5 leaks along the vertical joint and extends along a horizontal joint and water is leaking onto the adjacent roadway, creating significant ice buildup and hazardous conditions on the road during winter. Division #9 has diagonal cracks and horizontal joints that are leaking. Temporary sealing repairs were performed at some sections in 2000, however, these sections are leaking again.

2. Stop log sluiceway structures

There are four stop log sluiceways at Chats Falls GS: Merrill Island, Wolverine Chute, Ragged Chute and Victoria Island. The stop log sluiceways at Chats Falls were designed with steel gains and utilized wooden stop logs, which are removed and installed in the sluiceway using a mechanical log lifter located on the upper deck of the structure. The stop log sluiceways are also afflicted with AAR, and major problems have developed the past several years.

As such, the 2008 Plant Condition Assessment (PCA) recommended concrete restoration of the decks, expansion joints and end piers at Merrill and Wolverine sluiceways. The Victoria Island sluiceways are in better condition and require less repair. Surveys and reviews have also been undertaken over a number of years in response to concerns over inward movement of stop log sluiceways end piers due to AAR. This inward movement has led to a reduction of the distance between the gains of the sluiceways and inability to remove or install stop logs in the end sluices. The movement of the gains due to concrete growth jammed the wooden logs making these sluices inoperable.

2.1 Merrill Island & Wolverine Chute Sluiceways

The Merrill Island & Wolverine chute sluiceways respectively consist of 22 and 10 stop log sluiceways. Both structures are entirely located in the Province of Quebec. For both structures, there are signs of movement and horizontal cracking on both end piers, and portions of the deck are collapsing due to the pier movement. Rotation of the end piers resulted in closing of the log gains and the stop logs are jammed in position and cannot be removed. The proper gain opening dimensions need to be re-established so that new logs can be installed.

2.2 Victoria Island Sluiceway

The Victoria Island sluiceway consists of 10 stop log sluiceways. There are signs of some minor movement on both end piers. New stop logs were installed in October 2009.

Concrete deterioration

1. Gravity sections

All gravity sections are showing signs of concrete erosion at the waterline as a result of the water and ice action. There is also significant concrete deterioration along the vertical joints on the upstream face of the dam, and significant surface scaling on the crest along both edges where the handrails are anchored. This deterioration results in structural issues with the handrail anchorage as well as an uneven walking surface. The downstream face has severely deteriorated concrete surfaces due to leakage through joints, spalling of concrete due to freeze-thaw action and vegetation growth.

2. Stop log sluices structures

All stop log sluice structures show signs of concrete erosion at the waterline elevation on the exterior piers, as a result of the water and ice action. There is major surface scaling and spalling on the crest of the sluiceway sections, along both edges where the handrails are anchored. This deterioration results in structural issues with the handrail anchorage.

A technical specification was prepared and includes several types of repair methods that have been specifically developed for the different types of problems. This approach will ensure that for each type of deficiency, the most appropriate repairs will be performed to achieve optimum results and achieve maximum extension of the service life.

Handrail issues

1. Handrails

The gravity sections & stop log sluices structures are equipped with different types of handrails that do not meet OHSA regulations. Replacement of the handrails and installation new anchors was recommended. The existing cast iron upstream railing is poorly anchored in many locations, making the railing loose and generally unsafe for site staff. The railing on the Merrill Sluices has been temporarily stabilized. The paint on the railing has been tested positive for lead contamination. The assessment from 2010 clearly stated the need to remediate the situation by replacing all 5km of handrails with a new design.

4. ALTERNATIVES & ECONOMIC ANALYSIS

The Present Value of the total project costs are shown in the table below. Although the present value of the recommended alternative (Alt.3) is $7.4M worse than deferring the project for an additional 12 years (Alt.2), the dam safety and operational risks associated with a deferral are considered to be unacceptable.

	Base Case	Alt 1	Alt 2	Alt 3 (Recommended)
Remaining costs (k$)	0	$49,869	$58,984	$39,846
PV (2012) (k$)	0	($26,452)	($17,768)	($25,216)

Base Case: ***Status Quo (Do not conduct any concrete repairs or handrail replacement).***

- **Not Recommended**

This option is not recommended because it will not address the deficiencies outlined in the Background & Issues section. The option of leaving the stop log sluiceway end piers and expansion joints in the existing state with no concrete restoration is not recommended because it does not address the current concerns with structural integrity and operational problems which will lead to dam safety problems and possibly plant decommissioning or rebuild.

Alternative 1: ***Restore the gravity sections only – Defer stop log sluices repairs five years.***

- **Not Recommended**

This alternative consists of complete restoration of all gravity sections, as well as replacement of both upstream and downstream handrails. Concrete restoration for the gravity sections includes sealing and reinforcement of cracks and construction joints, sealing of underwater cracks, restoration of deck edges and upstream dam face, restoration of eroded concrete at the waterline, and removal of deteriorated concrete and vegetation on downstream face. The scope of work also includes the restoration of the bulkhead Division #9 which is currently experiencing severe leakage, concrete deterioration and structural integrity issues.

- This alternative will reduce leakage through the dam as much as practical, and mitigate further concrete deterioration.
- This alternative will allow OPG to extend the service life of the water retention structures and avoid major concrete restoration work for a minimum of 40 years.
- This option will address the current problems with old and non-compliant handrails.

This option does not address current issues and concerns associated the four stop log sluiceways. Stop log sluices structures will continue to deteriorate and could eventually result in significant operational problems of removal and installation of the stop logs. There is a risk of failure of the stop logs leading to an uncontrolled released of water. There are additional risks with loss of structural integrity caused by severe deformations of the stop logs which could result in partial collapse, having a significant negative impact on the Health & Safety of the workforce, and unfavorable consequences to the reputation of both OPG and Hydro Québec. Loss of structural integrity could also result in major Dam Safety incident with the uncontrolled release of water. This could result in eventual plant/dam decommissioning or rebuild.

➔ Cost = approx. $49,869k
➔ PV of Costs = ($26,452k)

Alternative 2: ***Restore the stop log sluices only – Defer gravity sections repairs 12 years.***

- **Not Recommended**

This alternative consists of performing complete restoration of all four stop log sluiceway structures, as well as replacement of both upstream and downstream handrails. Concrete work associated with this alternative consists of removal and reconstruction of concrete decks of the first and last sluice ways of both Merrill Island (Division 12) and Wolverine Chute (Division 10). The piers will also be repaired.

This alternative also includes resurfacing of concrete decks at all stop log sluiceways, and re-sealing of all expansion joints. The existing wooden stop logs will be replaced with pre-fabricated steel stop logs and rails for the log lifters will be reinstalled and re-aligned.

- This alternative will ensure that operational risks associated with deformed concrete structures are mitigated;
- This alternative will allow extension of the service life of the sluiceways for 40 years.

While this alternative will aid OPG in protecting its assets and reduces some risks, this option will not address current issues and concerns associated with deteriorated gravity sections. The gravity sections will continue to deteriorate, additional structural issues will develop, and future project costs will escalate due to continued deterioration. Proceeding with this alternative could also have severe implications for the long term stability of the dam due to increased leakage, and erosion, which could lead to eventual plant/dam decommissioning or rebuild.

➔ Cost = approx. $58,984k
➔ PV of Costs = ($17,768k)

Alternative 3: ***Restore the gravity sections and all four stop log sluices structures without any deferrals.***

- **Recommended**

This alternative consists of the complete rehabilitation of all gravity sections including all four stop log sluiceways, as well as replacement of upstream and downstream handrails. This alternative includes the work scope of both alternative #1 (restore the gravity sections) and alternative #2 (restore the stop log sluiceway structures).

- This alternative will mitigate the operational risks associated with deformed concrete structures and sluiceways.
- This alternative will allow a 40 year extension of the service life of the main gravity dam and sluiceways.
- This option will reduce leakage and mitigate further concrete deterioration.
- This option will address the current deficiencies with old and non-compliant handrails.

This option will provide the best financial solution while minimizing risks to the structures, personnel and the public. It will also allow the project to be completed within the planned five years of work.

➔ Cost = approx. $39,846k
➔ PV of Costs = ($25,216k)

Other alternatives considered but rejected

Alternative 4: ***Defer execution of the entire project till 2017.***

- **Not Recommended**

This alternative postpones the execution of the work by five years. This option is technically unacceptable due to the significant dam safety risks of failure of the dam or sluiceway structures and loss of flow control capability of some sluiceways. This would also negatively impact OPG & Hydro Québec's public reputations. This option would not properly mitigate current deficiencies with non-compliant handrails. Finally this option would cause accelerated deterioration to the concrete structures resulting in significant increases in future repair costs estimated at 20% the five year period.

Alternative 5: ***Restoration of the gravity sections, all four stop log sluices structures plus applying sealant to the concrete structures.***

- **Not Recommended**

This alternative includes the same scope of work as Alternative #3 but with the addition of a special concrete penetrating sealant on the structures (approximate cost of $1 M). The dam was constructed in the 1930's without added air entrainment, a technology that was not available at the time of construction. Application of concrete sealant may better protect the surfaces from moisture ingress and slow down the amount of water infiltrating the concrete preventing further surface deterioration. Application of such a sealant may extend the service life for an estimated five years by minimizing water infiltration in the concrete and reducing the impact of freeze-thaw cycles as well as reducing future vegetation growth. However, this is an assumption which cannot be confirmed by the project's engineering support, nor will the contractor guarantee the service life extension. Although this option was found to be technically acceptable, there is no financial benefit to proceed with this as the Net Present Value is worse than Alternative #3.

5. THE PROPOSAL

Restoration of the stop log sluices, head works and main dam gravity sections at Chats Falls Generating Station as per Alternative #3 will include:

- Complete rehabilitation of all gravity sections (including sealing and reinforcement of cracks and construction joints, sealing of underwater cracks, restoration of deck edges and upstream face, restoration of concrete at waterline erosion, removal of deteriorated concrete and vegetation on downstream face).
- Complete restoration of all four stop log sluiceway structures (including removal and reconstruction of concrete decks of the first and last sluice ways and reconstruction of the piers and replacement of all exterior sluices.
- Resurfacing of concrete decks on all stop log sluices structures.
- Re-sealing of all expansion joints.
- Reinstallation & re-alignment of the log lifter rails.
- Recoating of the steel beams currently installed in the log chute (Division 8) to help minimize corrosion and extend their service life.
- Replacement of both upstream and downstream deteriorated and non-compliant handrails.

This project will restore the dam structures and associated equipment to address existing deterioration, operational problems, and emerging dam and personnel safety concerns and extend the service life of the dam and sluiceways for about 40 years. It also addresses the safety hazards associated with old and non-compliant handrails. The project will also minimize any negative impacts to OPG's public reputation associated with the failure of the dam or sluiceway.

The project will be completed over 5 years. Due to MNR restrictions, the in-water work cannot commence before July 15th and cannot be extended beyond Oct. 15th each year. OPG provided the contractors the historical flow and spill conditions during the RFP process, and based on these conditions and the restrictions regarding in-water work the execution needs to take place over a five year period. Hydro Québec were consulted regarding the cost/schedule and agree with the project execution plan.

6. PROJECT SCHEDULE

Q1 2012: Project Release

Q2 2012: Issue Purchase Order
June 2012: Construction work at site commencement

June to Nov. 2012:

- Sealing of underwater cracks (includes reinforcement where required) on Division 13.
- Concrete repairs (in water work) on Divisions 13 & 14.
- Concrete repairs (not in water work) on Divisions 13 & 14.
- Handrail replacement, utilities & cables trays work on Divisions 13 & 14.

May to Nov. 2013:
- Sealing of underwater cracks (includes reinforcement where required) on Division 9.
- Repairs on Division 12 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (in water work) on Division 9.
- Installation of stress crack anchors and epoxy injection on Division 9.
- Concrete repairs (not in water work) on Division 9.
- Handrail replacement, utilities & cables trays work on Divisions 9 & 10 (stage with other repairs as required).

May to Nov. 2014:
- Sealing of underwater cracks (includes reinforcement where required) on Division 11.
- Repairs on Division 10 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (in water work) on Divisions 10 & 11.
- Concrete repairs (not in water work) on Divisions 6, 7, 8, 10 & 11.
- Hand rail replacement, utilities & cables trays work on Div 6,7,8,10,11.

May to Nov. 2015:
- Sealing of underwater cracks on Divisions 3 & 5.
- Concrete repairs (in water work) on Divisions 3 & 5.
- Concrete repairs (not in water work) on Divisions 3 & 5.
- Handrail replacement, utilities & cables trays work on Divisions 3, 4 & 5 (stage with other repairs as required).

May to Nov. 2016:
- Sealing of underwater cracks on Division 1.
- Concrete repairs (in water work) on Divisions 1 & 2.
- Repairs on Division 2 (coffer dam, anchors, gains, deck repairs including overlay, rail replacement, etc.).
- Concrete repairs (not in water work) on Divisions 1 & 2.
- Handrail replacement, utilities & cables trays work on Divisions 1 & 2 (stage with other repairs as required).

December 2016: Project execution complete.

June 2017: Project Closure Report (PCR).

7. QUALITATIVE FACTORS

- Mitigate the risks of an uncontrolled release of water at the sluiceways with jammed stop logs.
- Improved reliability of the stop log sluices structures and gravity (bulkhead) sections, continued availability of the assets will be maintained and protected;
- Service life extension of the structures;
- Minimization of the damage caused by freeze-thaw action, waterline erosion, leakage, etc;
- Work assignment has been designated in accordance with PWU/BTU Chestnut Park Accord process;
- This work will mitigate the emerging Dam Safety concerns with the gravity sections and stop log sluiceway structures;
- This work will eliminate any safety concerns with the handrails.

8. POST IMPLEMENTATION REVIEW (PIR)

For each year of programmed work:

- After completion of the annual work, an engineering assessment to verify conformance to the engineering specifications will be performed by the engineering consultant and results will be documented in a yearly conformance report.
- Discrepancies and deviations from the technical requirements will be addressed through a review meeting and directions for subsequent work will be obtained.
- OSPG Environmental Support Unit (ESU) will perform a yearly evaluation of the work to confirm absence of negative impact on the environment.

At the end of the project (scheduled for October 2016):

- OSPG Asset Management (in coordination with Chats Falls Production) will confirm overall conformance to the initial technical specifications and that the following elements were properly addressed, which shall include:
  - ➢ Reduction of leakage in the gravity sections;
  - ➢ Removal of all vegetations on the gravity sections;
  - ➢ Repairing the upstream & downstream surfaces of the gravity sections;
  - ➢ Restoration of the walking surfaces on the decks and elimination of spalled concrete;
  - ➢ Elimination of the operational problems associated with stop log sluiceways;
  - ➢ Replacement of all handrails with OHSA compliant designed handrails;
- Asset Management in coordination with Dam Safety will evaluate the conformance and integrity of the rehabilitated structures and confirm performance against Dam Safety standards.
- OSPG Environmental Support Unit (ESU) will confirm that the work executed did not negatively impact the environment.

9. RISK ANALYSIS

Risk Description	Impacts	Initial Risk (before mitigation) (H,M,L)	Mitigating Activities	Residual Risk(after mitigation) (H,M,L)
Cost				
• Material and supplies costs escalation.	• Exceeding the release amount.	M	• Award of the contract will be done under fixed price agreement; • Detailed assessment showed the extent of the work involved in providing the deliverables;	L
• Labor cost escalation.	• Exceeding the release amount.	M	• Award of the contract will be done under fix price agreement; • Escalation included in fixed price; • BTU labor agreements are mostly known for the duration of the project.	L
Scope				
• Not performing or deferring the full release.	• Major risks related to structural integrity and possible equipment failure; • Increased mitigation costs.	H	• Accountability for plant production staff to perform annual localized guardrail inspection & repair.	L
• Possibility of discovery work.	• Escalated execution costs • Negative impact on the schedule and delay of the completion dates.	M	• Detailed assessment showed the extent of the work involved in providing the deliverables; • [redacted] contingency included to address unknown additional scope items.	L
Schedule				
• Delays in obtaining the deliverables	• Would delay the execution phase.	L	• Fixed schedule contract with hourly rates. • Delivery dates will be implemented and enforced in award of contract.	L

Risk Description	Impacts	Initial Risk (before mitigation) (H,M,L)	Mitigating Activities	Residual Risk(after mitigation) (H,M,L)
• Project is not completed within the agreed 5 year window.	• Would delay the execution phase. • Would incur extra costs to the contractor/OPG.	M	• Fixed schedule contract. • OPG provided station historical flows & times of sluicegate operation. Contractor developed the five year schedule as per the historical operation of the facility.	L
• OPG requires full access to work site, stopping contractor work.	• Negative impact on the schedule and delay of the completion dates; • Escalated execution costs.	H	• Contractor to be aware of possibility that OPG may require access to site and will plan accordingly; • OPG will work closely with contractor to minimize impact on work execution from unnecessary site access.	L
• Contractor initiates and continue in-water work outside the MNR allowed period	• Fines from the Ontario MNR.	L	• An execution schedule provided by contractor will be approved by OPG prior to being used by contractor. • No in-water work to be executed prior to July 15th of each year.	L
Resources				
• Union strike or other work stoppage	• Negative impact on the schedule and delay of the completion dates; • Escalated execution costs.	L	• CPA Collective agreements recently ratified provide up to 3 years without labor concerns.	L
Environmental				
• Construction or demolition materials enter the Ottawa River or are disposed of on firm lands.	• Possibility of fines from the Quebec MNR as well as from the Ontario MNR; • Possible damage to the ecosystems and natural resources.	M	• Proposals will include complete plan to minimize or eliminate as much feasible potential spills and releases of materials into the environment; • OPG prepared a complete environmental specification to accompany the work; • Site manager will monitor to ensure conformance with the environmental specification.	L
• Sensitive species are disturbed or negatively impacted.	• Partial or total loss of local population of sensitive species, with potential regulatory and stakeholder consequences.	L	• Proponent's proposals will include complete plan to minimize any negative impacts on sensitive species. • Certain wildlife habitats may be relocated for the duration of the work to minimize any impacts.	L

ONTARIO POWER GENERATION

HYDROELECTRIC Summary of Estimate

Date	February 12, 2012
Project #	CHAF0035

Facility name: Chats Falls GS

Project Title: Main Dam Concrete Restoration

	2011 LTD	2012	2013	2014	2015	2016	TOTAL	%
Capital								
Project Management / Engineering (012)		$ 225	$ 232	$ 239	$ 246	$ 253	$ 1,195	3%
Consultant / Engineering (310)	[redacted]							
Construction/Installation								
Hydroelectric (PWU labour) (10)		$ 65	$ 67	$ 58	$ 71	$ 134	$ 395	1%
Contractor / (BTU labour) / EPSCA (310)	[redacted]							
Interest (700)							$ -	0%
Contingency (998)	[redacted]							
TOTAL (GROSS)	**$ 162**	**$ 7,440**	**$ 8,315**	**$ 8,353**	**$ 8,200**	**$ 7,530**	**$ 40,000**	**100%**
Hydro-Quebec Cost Recovery (840)	$ 81	$ 3,720	$ 4,158	$ 4,177	$ 4,100	$ 3,765	$ 20,000	50%
TOTAL (NET)	**$ 81**	**$ 3,720**	**$ 4,158**	**$ 4,177**	**$ 4,100**	**$ 3,765**	**$ 20,000**	**50%**

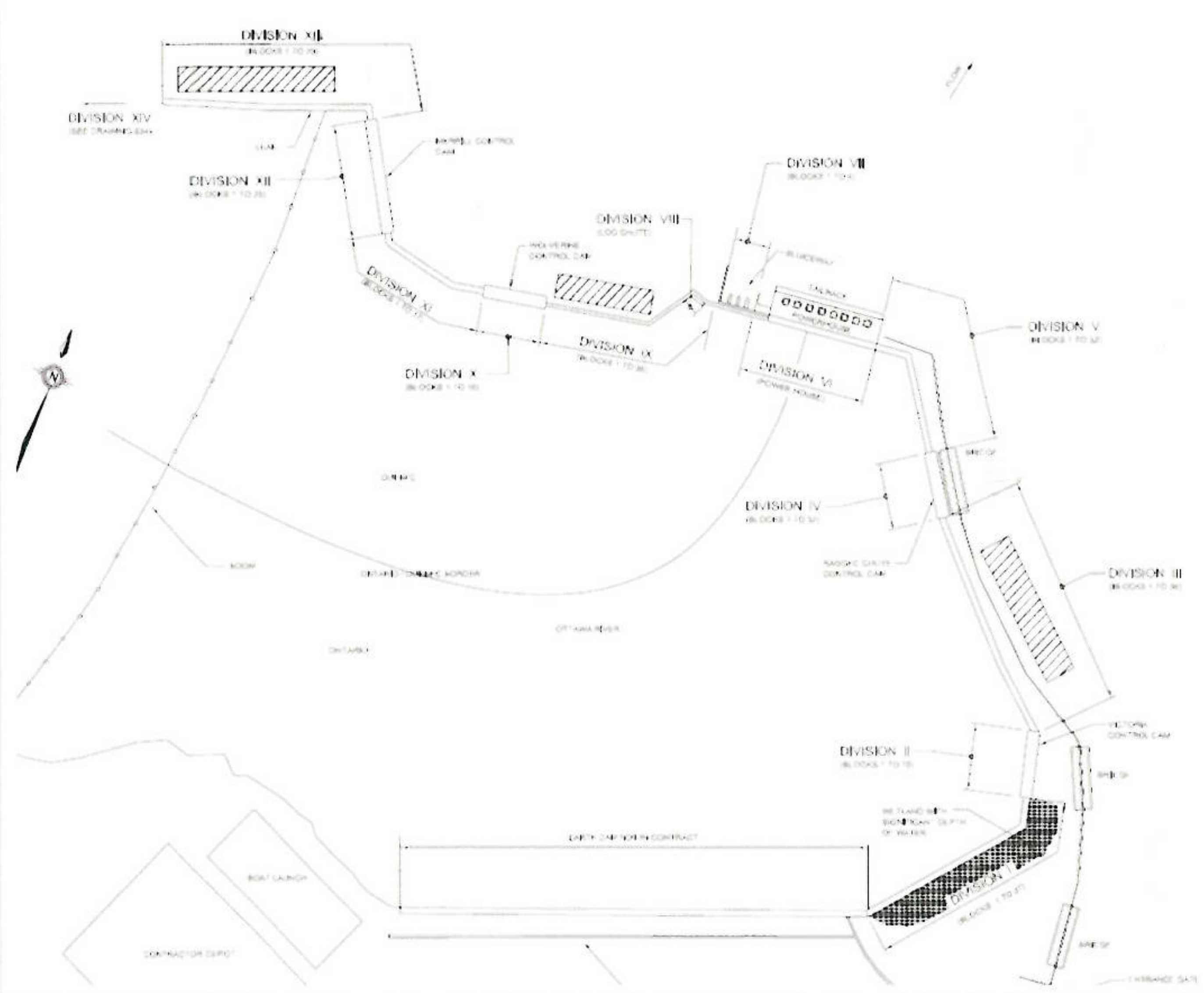
Costs in $k

Notes:

1. Schedule: Start Date: April 2012; In-service Date: November 2016
2. Escalation rates are based on current allocation rates provided by Corporate Finance

Prepared by: Chris Hamel	**Approved by:**
Chris Hamel, P. Eng.	Gerry Foote Gerry Foote
Project Engineer	*Production Manager*
Date: February 12, 2012	Date: Feb 14, 2012

Appendix A: Site plan – Chats Falls GS



ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary

Final Security Classification of the BCS: **Internal Use Only**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

Executive Summary and Recommendations

Project #:	SABP0053 SABP0056	**Title:**	PG3 Overhaul PG3 New Runner Blades
Phase:	Execution	**Release:**	Full
Facility:	SAB PGS (NF282)	**Records File:**	08707.021
Class:	Capital and OMA	**Investment Type:**	Sustaining

Project Overview

We recommend the release of $9,043 k ($[redacted]base costs plus $[redacted]contingency).

Sir Adam Beck (SAB) Pump Generating Station (PGS) is a six unit reversible pump-turbine plant capable of pumping water from the outlet of the tunnels and canal of the SAB complex, into a storage reservoir, and generating from that reservoir by discharging the stored water back into the SAB Complex head pond.

The primary driver for this project is to mitigate the environmental risk of a potential oil spill from a runner seal failure or oil leakage from the coupling flange between the runner and shaft. Other key drivers are to address reliability issues with major components and the risk of poor runner blade condition. Based on the PG6 overhaul experience, complete overhaul of the unit including replacement of the runner blades is required to reduce the oil leak risk and ensure reliable unit operation for 15 years.

The required funding for this project is broken down as follows:

k$	2013	2014	2015	Total
OM&A - SABP0053 Overhaul	1,995	4,347		6,342
Capital - SABP0056 New Runner Blades	424	1,646	631	2,701
Total Project Cost	**2,419**	**5,993**	**631**	**9,043**
BP13-15 OM&A - SABP0036 (Program)	1,200	4,050	4,500	9,750
BP13-15 Capital	0	0	0	0
Variance - OM&A	795	297	(4,500)	(3,408)
Variance - Capital	424	1,646	631	2,701

The unit will be overhauled from September 2013 to July 2014.

The NPG 2013-15 Business Plan BURSA identified PGS unit reliability (forced outage due to oil leakage or generator rotor spider arm cracking) as one of five key business risks for the plant group. The mitigation plan for this risk is to perform the planned overhauls as per the approved work program to address oil leakage issues, and to continue with the established NDE and repair program of the generator rotor.

A spare set of runner blades was purchased in July 2012 as a Capital Spare under project SABP0040 to mitigate the risk of runner blades not being acceptable for use on a unit during the PGS overhaul program. Due to the long lead time to manufacture a set of runner blades (~18 months), the capital spare set will be used on PG3 during this overhaul and the new blades purchased under this project will be put back into inventory as the Capital Spare to protect the remainder of the overhaul program.

[redacted]

Execution of this work will address oil leakage issues, reliability issues with other components, and poor runner blade condition on PG3 and help to refine the scope of work and associated costs for the rest of the units.

Type 3 Business Case Summary

Project Cash Flows									
k$	LTD	2013	2014	2015	2016	2017	2018	Future	Total
Currently Released									
Requested Now		2,419	5,993	631					9,043
Future Required									
Total Project Cost		2,419	5,993	631					9,043
Ongoing Costs		0	0	0					0
Grand Total		2,419	5,993	631					9,043

Estimate Class:	Class 3	**Estimate at Completion:**	9,043
NPV:	$ k	**OAR Approval Amount:**	9,043

Additional Information on Project Cash Flows (optional):

The 2013 budget includes funding of $1,200k OM&A for the PGS overhaul program. Changes will be managed within the Plant Group budget envelope.

Approvals			
	Signature	Comments	Date
This BCS represents the best option to meet the validated business need in a cost effective manner.			
Recommended by: Al Reid Plant Group Manager, Niagara Plant Group Project Sponsor	Allan Reid		May 10/13
I concur with the business decision as documented in this BCS.			
Finance Approval: Don Power VP Investment Planning			May 14/2013
I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Frank Chiarotto SVP HTO, per OAR 1.2			May 15, 2013

ONTARIOPOWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary

Final Security Classification of the BCS: **Internal Use Only**

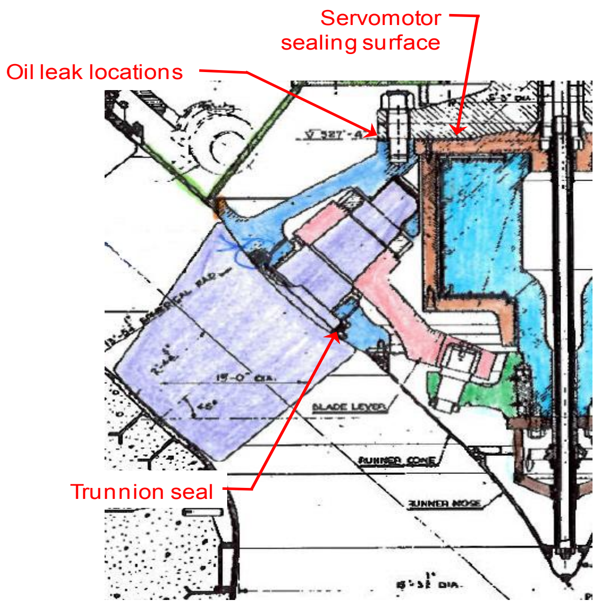
Business Case Summary

Part A: Business Need

Business Need:

The primary driver for this project is to mitigate the environmental risk of a potential oil spill from a runner seal (trunnion seal) failure or oil leakage from the coupling flange between the runner and shaft. Other key drivers are to address reliability issues with major components and the risk of poor runner blade condition.

The following sketch is a section through the runner hub showing key runner components and leak locations. Refer to Appendix E for a full drawing of a PGS unit and the location of the runner assembly in relation to the entire unit.



Additional benefits to be gained from this project are:
- ensure reliable unit operation for 15 years
- opportunity to improve thrust bearing performance
- opportunity to improve the shaft seal on PG3

PG3 was selected as the first unit to be overhauled for the following reasons:
- long time since last overhaul (~15 years at 2013)
- worst internal oil leakage based on governor pump recycle time
- worst blade cavitation damage and blade profile
- still has the original 1957 design vulcanized trunnion seals

In accordance with the OPG standard investment management program, the Life Cycle Plan for the PGS is under development. Early assessment of the LCP indicates that it is favorable to invest in the overhaul on PG3. This does not commit OPG to investment in the remaining units until the LCP is approved.

SAB PGS is a six unit reversible pump-turbine plant capable of pumping water from the outlet of the tunnels and canal of the SAB complex, into a storage reservoir, and generating (174 MW capacity) from that reservoir by discharging the stored water back into the SAB Complex head pond. The station produces an average of 120 GWh/year. Also, there are a number of unique benefits that result from PGS operation which include:

1. Ability to pump water into storage at times of low demand, so that it can be later released for generation at times of high demand (peaking capability).
2. Level control for SAB1 and SAB2 head pond which allows the level to be adjusted for better unit efficiency.
3. Additional water that can be used for peaking at SAB1 and SAB2 - each PGS unit contributes up to 4,500 cfs to the SAB head pond when operating at maximum efficiency.

This unique operational profile results in more stops and starts than a conventional generating station as the units switch between pump and generation modes. In addition, units at the PGS are required to change blade pitch (often several times per minute) in response to the cross-over level controller, which contributes significantly to increased component wear. Because of the unique nature and operating characteristics of the PGS, the expected runner overhaul period is more frequent than conventional hydro units.

The original equipment manufacturer of the PGS vertical Deriaz runners was the English Electric Co. whose assets were purchased by Alstom. Alstom is now the only company which has access to the OEM construction drawings, specifications and procedures.

In 2008, PG6 was removed from service (only 9 years from its previous overhaul) due to oil seepage through the coupling flange between the runner and shaft. Attempts made to repair the leak without dismantling the unit were not successful. A complete overhaul of the unit was required to correct the deficiencies, which necessitated shipping the runner to the OEM. Key observations were made on the physical condition of a number of critical runner components during the PG6 overhaul and recommendations were made by Alstom, under the guidance of OPG's Technical Engineer.

There is the potential during the unit overhauls to find that the runner blades are not acceptable for use, either due to damage (cavitation, corrosion, cracking) or excessive deviation in blade profile. If the existing blades cannot be used, the unit would be forced out for 18+ months while a new set of blades are manufactured. To mitigate this risk, a set of blades was purchased for $2.8M as a Capital Spare under project SABP0040.

The current condition of the PG3 runner blades is not fully known. However, based on anecdotal history of blade damage, blade profile, and operational issues, the Engineering judgement is that the blades will not be acceptable for use. Therefore, the project is planning to replace the PG3 runner blades with the Capital Spare blades during the overhaul, and the new set of blades purchased under this project will be put back into inventory as the Capital Spare to protect the remainder of the overhaul program.

A Periodic Facility Condition Assessment (PFCA) for the PGS was completed in November 2010. Recommendations from the PFCA are being incorporated into the scope of work for this project and include:

1. Turbine - Inspect and correct all fits between the blade assembly and the servomotor assembly (PG6 scope).
2. Generator - Continue current program of NDT to monitor for cracks in the rotor and install telltales to monitor tightness of rims and effectiveness of the rim shrinks. Stator winding dog bones should be lashed.

The NPG 2013-15 Business Plan BURSA identified PGS unit reliability (forced outage due to oil leakage or generator rotor spider arm cracking) as one of five key business risks for the plant group. The mitigation plan for this risk is to perform the planned overhauls as per the approved business plan to address oil leakage issues, and to continue with the established NDE and repair program of the generator rotor.

The procurement strategy for the PG1-5 runner assemblies is to sole source the overhauls to Alstom with a scope of work similar to that performed for PG6. Included with the sole source justification is the supply and installation of new blades on each unit if required. The contract with Alstom will be structured to perform the overhaul on PG3, with options for overhaul of each of the remaining units. [redacted]

The Trades Work Assignment for the remaining project work was completed January 22, 2013. Disassembly, repairs to mechanical/electrical equipment and systems, installation of a PTFE thrust bearing, assembly, alignment, and commissioning was assigned to the PWU. The NPG Production department has committed to fully resourcing this work with PWU staff.

The BTU was assigned the installation of a new Fugesco seal, replacement of bearing cooling water piping, and installation of ultrasonic flow meters, an oil mist eliminator, and a kidney loop filtration system. The procurement strategy for the BTU assigned work is to competitively bid the work to general contractors approved by OPG. The contract will be structured to perform the work for PG3, with options for each of the remaining units.

A Project Definition Rating Index (PDRI) assessment was completed Mar.19, 2013. The result was a normalized PDRI score of 328 (out of 1000) which was desirable at this stage in the project life cycle. The team scored well on the basis of project decision but identified the basis of design as requiring additional definition. Finalization of the Tech Spec for the design and supply of the PTFE bearing, kidney loop filters, and oil mist removal system will address many of the less defined items.

Type 3 Business Case Summary

Part B: Preferred Alternative		
Description of Preferred Alternative: Rehabilitate PG3 Rehabilitate the existing PG3 runner, including repairing the servomotor, modify and/or replace seals and sealing surfaces, and other minor runner repairs as required. Install new runner blades. Complete other work on the unit that is consistent with a major overhaul and work consistent with the PFCA results. The existing servomotor is not at end of life, is in acceptable condition, and can continue to be maintained. The current condition of the existing runner blades is not fully known. However, based on anecdotal history of blade damage, blade profile, and operational issues, the Engineering judgement is that the blades will not be acceptable for use. Therefore, they will be replaced with new runner blades during the overhaul. If the blades are not replaced, the unit would require another long duration outage in approximately 7 years to fully disassemble the unit, inspect the runner blades, and re-assemble. The existing generator rotor spider arms are not at end of life, are in acceptable condition, and can continue to be maintained. The unit will be overhauled from September 2013 to July 2014. This alternative will address the potential oil leak issue that currently exists on PG3, provide reliable unit operation for 15 years, and has the lowest estimated project cost.		
Deliverables:	**Associated Milestones (if any):**	**Target Date:**
Contract with Alstom finalized	P.O. issued to Alstom	May 24, 2013
RFP process for general Contractor complete	P.O. issued to Contractor	Aug. 30, 2013
PG3 taken out of service	Outage start	Sept. 17, 2013
Overhaul work complete	PG3 RTS	July 15, 2014

Type 3 Business Case Summary

Part C: Other Alternatives
Base Case: Status Quo – No Project Continue to execute the existing LEM program for unit maintenance which does not include any unit disassembly. Maintenance costs will increase each year as the unit continues to wear. This alternative is not acceptable as it does not address the runner seal issues and may lead to oil leakage or reduced pump/generator availability.
Alternative 2: Rehabilitate PG3 including Replacement of Major Components Rehabilitate the existing PG3 runner by replacing the aging servomotor, replacing runner blades, and replacing/ modifying seals, sealing components and related surfaces. Replace the generator rotor spider. Complete other work on the unit that is consistent with a major overhaul and work consistent with the PFCA results. The existing servomotor is not at end of life, is in acceptable condition, and can continue to be maintained. A like-for like replacement would provide no additional benefit. The existing generator rotor spider arms are not at end of life, are in acceptable condition, and can continue to be maintained. Replacement with a new design that doesn't have the cracking issues would reduce maintenance but the high cost cannot be justified. This alternative will address the potential oil leak issues that currently exist on PG3 and will provide a more efficient unit. However, the incremental efficiency benefit to be gained does not justify the higher project cost.
Alternative 3: Replace Existing PG3 Runner, Overhaul Generator Complete runner, including servomotors and blades, would be replaced with a modern high efficiency unit. The efficiency increases gained would allow longer PG3 operation with existing generator and reservoir configuration. This alternative requires a complete redesign of the PGS units and would take an estimated 2 years to redesign and another 1 to 2 years to install on the first unit. This will continue to leave the PGS at a high risk of a potential oil spill or oil leakage for at least 3-4 additional years. Some design issues to consider are: - shaft and rotor may be inadequate to handle higher stresses due to increased loading - stator may not be able to handle the increased power from the unit - major modifications may be required to install wicket gates The estimated cost for this alternative is $15-20M per unit. This alternative is not recommended due to the high project cost.
Alternative 4:

Part D: Project Cash Flows

k$	LTD	2013	2014	2015	2016	2017	2018	Future	Total
Currently Released									
Requested Now	-	2,419	5,993	631					9,043
Future Required	-								
Total Project Cost		2,419	5,993	631					9,043
Ongoing Costs	-	0	0	0					0
Grand Total		2,419	5,993	631					9,043

Estimate Class:	Class 3	**Estimate at Completion:**	9,043	**OAR Approval Amount:**	9,043

Additional Information on Project Cash Flows (optional):

The 2013 budget includes funding of $1,200k OM&A for the PGS overhaul program. Changes will be managed within the Plant Group budget envelope.

Part E: Financial Evaluation

k$	Rehabilitate PG3	Status Quo	Rehabilitate PG3 incl. Replace Major Components	Replace PG3 Runner, O/H Generator	
Project Cost	9,043	N/A	14,000	20,000	
NPV (after tax)					
Other					

Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):

A Financial Evaluation was not completed for this project since this is sustaining work that was similarly performed on PG6.

Note that a Financial Evaluation of the PGS was performed as part of the PGS Reservoir Refurbishment project which is being managed by Hydro Development Engineering. In the Definition Phase BCS, the economic assessment showed that there is approximately a $470M net present value to the Ontario electricity system based on evaluation of capacity value and the peaking energy value of the ongoing operation of PGS compared to shutdown of the facility. This economic analysis was over a 50 year period and included overhauls of PG1-5.

Changes in the key assumptions since the Definition BCS was released in Sept 2011 are shown in the following table:

$M	Def BCS	2013 Forecast	Variance
Estimated cost of reservoir refurb project	255	100	(155)
Overhauls (5 units)	25	29.5	4.5
Runner blade replacement (6 units)	15	16.8	1.8
Totals	**285**	**146.3**	**(138.7)**

Based on these changes, the economic assessment in the PGS Reservoir Refurbishment project Definition BCS is still valid.

Part F: Qualitative Factors

Ensure availability of PG3 to preserve the ability to time shift water from off-peak to peak periods.

Type 3 Business Case Summary

Part G: Risk Assessment				
Risk Class	**Description of Risk**	**Risk Management Strategy**	**Post-Mitigation**	
			Probability	**Impact**
Cost	Costs higher than expected	Allowances have been included in the RQE for known unknowns. This will be relinquished as necessary during the project. Contingency ([redacted]) included.	Low	Low
Scope	Discovery work	The scope was prepared based on PG6 work scope in 2008 and PFCA recommendations. Allowances have been made for repairs based on findings.	Medium	Low
Schedule	Delays to project schedule if PWU crews pulled off project work.	Commitment from Production to provide adequate resources.	Low	Medium
Resources	Maintenance crews pulled off project work to perform other priority work	Commitment from Production to provide adequate resources. A proper resource plan needs to be developed. An overhaul crew will be formed.	Low	Medium
Quality/ Performance	Poor quality of work	An ITP will be developed for testing, start-up, and commissioning.	Low	Low
Technical	Improvements to turbine shaft seal and coupling bolt/stud seals don't work	Changes to match PG6 modifications. Alstom to pressure test servomotor and assembled runner hub to guarantee against leaks for a period of 10 years	Low	Medium
Cost	OM&A costs higher due to repairing instead of replacing runner blades	Accept increased OM&A costs. New PG3 set of blades becomes a spare for the rest of the program.	Low	Low
Schedule	Overhaul work during winter months, delays due to poor weather when hatch covers are open (craning)	There is sufficient time and flexibility in the schedule to manage these delays.	Low	Low
Technical	New design of thrust bearing (using PTFE) does not work or fails	PES prepare tech spec and provide technical assistance during install and commissioning. If it fails, replace with existing design and don't use on other units.	Medium	Low
Technical	Alternate design of trunnion seal by Alstom	If a new seal cannot be designed, all seals will be replaced with the design used on PG6. If a new design can be provided, it is to be guaranteed for 10 years. OPG will have to decide if this is a risk we want to accept.	Medium	Medium
Environment	Oil spills during the overhaul	Use NPG approved instructions.	Low	Low
Additional Risk Analysis:				

Part H: Post Implementation Review (PIR) Plan		
Type of PIR	**Target Project In Service Date**	**Target PIR Completion Date**
Simplified	July 15, 2014	December 30, 2015

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Runner assembly oil leakage	< 300 mL/day	0 mL/day	Pressure test at Alstom facility	NPG & PES Tech Support Engineers
Unit internal oil leakage	49 gal/min	< 25 gal/min	Readings per PGS Leakage Assess	NPG Tech Support Engineer
Correct fabrication of set of runner blades and transfer to Cap. Spare asset class	N/A	As per drawings and tech specifications	Inspections as per QA/QC programs	PES Tech Support, Asset Engineer

Part I: Definitions and Acronyms

ITP - Inspection & Test Plan
LCP - Life Cycle Plan
LEM - Leading Edge Maintenance
NDE - Non-Destructive Examination
NDT - Non-Destructive Test
NPG - Niagara Plant Group
PES - Plant Engineering Services
PFCA - Periodic Facility Condition Assessment
PGS - Pump Generating Station
PTFE - Polytetrafluoroethylene - a synthetic fluoropolymer of tetrafluoroethylene that finds numerous applications. The best known brand name of PTFE is Teflon.
RQE - Release Quality Estimate
SAB - Sir Adam Beck

This page is intentionally left blank

Type 3 Business Case Summary

Appendix A: Summary of Estimate										
Project Number:	SABP0053 SABP0056		**Facility:**	SAB PGS (NF282)						
Project Title:	P-G3 Overhaul / New Runner Blades									
Estimated Cost in k$										
	LTD	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Future**	**Total**	**%**
OPG Project Management		68	97						165	1.8
OPG Engineering		16	16						32	0.35
Permanent Materials	[redacted]									
Design and Construction		330	670						1,000	11.1
Consultants										
Other Contracts / Costs	[redacted]									
Interest		5	20	7					32	0.35
Subtotal	[redacted]									
Contingency										
Total		**2,419**	**5,993**	**631**					**9,043**	**1.0**
Removal Costs Included										

Note: All estimates shown in the table are for the combined OM&A and Capital portions. For breakdowns of OM&A and Capital estimates, refer to the individual RQE's.

Notes			
Project Start Date	2013-09-17	**Project Completion or In-Service Date**	2014-07-15
Interest Rate	5%	**Escalation Rate**	0%
Definition Cost Included	$0 k	**Estimate at Completion**	$9,043 k

Prepared by:	Approved by:
Greg Young Project Officer 2013-04-30	Dan Roorda Section Manager, Projects 2013-04-30

Type 3 Business Case Summary

Appendix B: Comparison of Total Project Estimates

Phase	Release	Date (YYYY-MM-DD)	Total Project Estimate in k$ (by year including contingency)						Later	Total Project Estimate
			2012	2013	2014	2015	2016	2017		

Project Variance Analysis

Estimated Cost in k$

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management			165	n/a	This is a new project. All estimates shown in the table are for the combined OM&A and Capital portions. For breakdowns of the OM&A and Capital estimates, refer to the individual RQE's.
OPG Engineering			32	n/a	
Permanent Materials	[redacted]			n/a	
Design and Construction			1,000	n/a	
Consultants					
Other Contracts/Costs	[redacted]			n/a	
Interest			32	n/a	
Subtotal	[redacted]			n/a	
Contingency				n/a	
Total			**9,043**	n/a	
Removal Costs Included					

Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

Project Cost:

(1)
(2)
(3)

Financial:

(1)
(2)
(3)

Project Life:

(1)
(2)
(3)

Energy Production:

(1)
(2)
(3)

Operating Cost:

(1)
(2)
(3)

Other:

(1)
(2)
(3)

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

Refer to SAB PGS Reservoir Refurbishment Definition BCS

Appendix D: References

PGS Periodic Facility Condition Assessment (Report No. R-NF282-01557-0003) dated November 2010

Definition Phase Project Charter for SABP0036 approved December 18, 2012

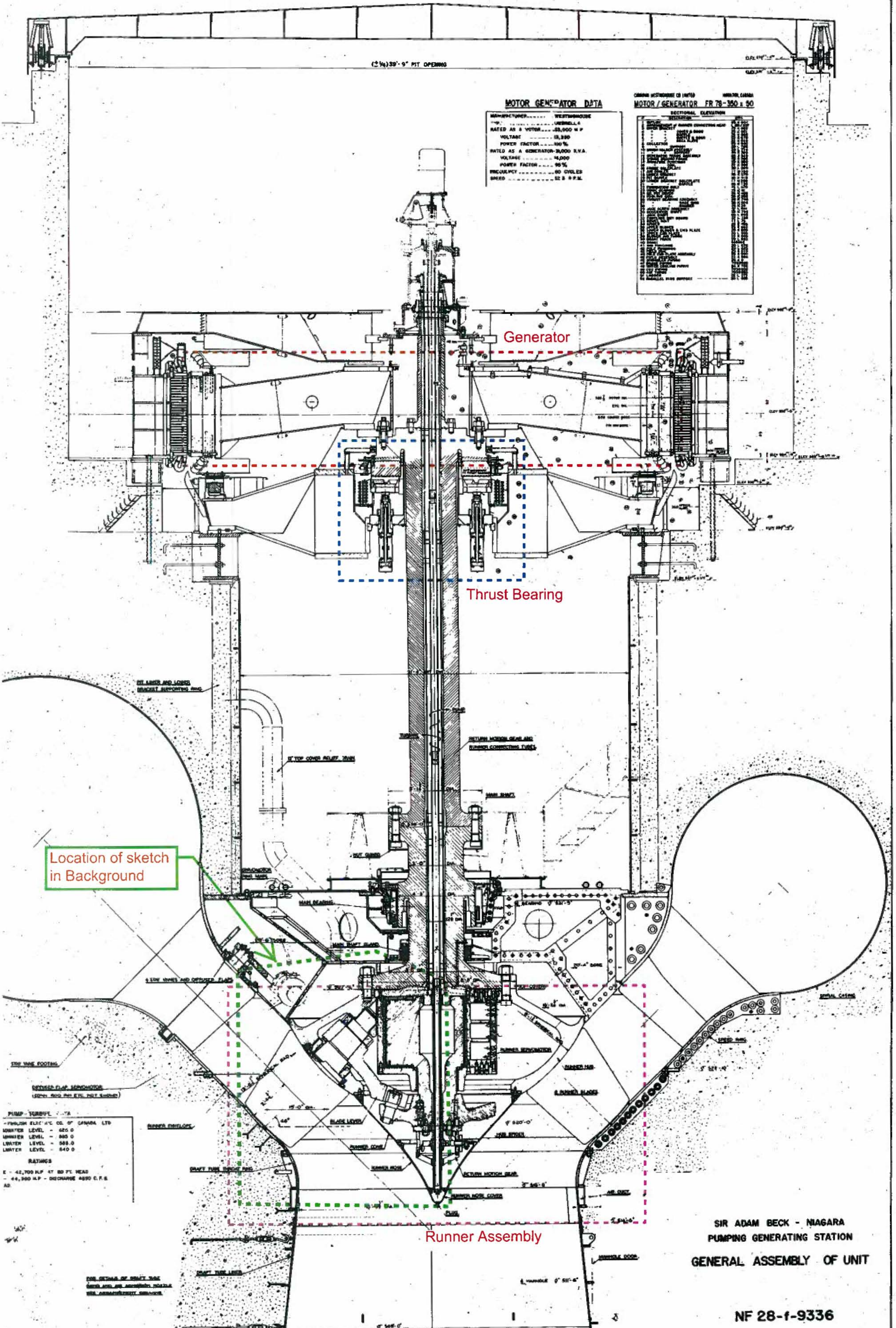
Business Plan 2013-2015

SAB PGS Reservoir Refurbishment Definition BCS (R-NF282-08707.021-0002) approved September 19, 2011

Release Quality Estimates - OM&A and Capital

Initial Project Execution Plan

Appendix E: PGS Full Unit Drawing



ONTARIO POWER GENERATION

Niagara Plant Group

RELEASE QUALITY ESTIMATE (RQE)

Summary Sheet (K$)

Date: 11-Apr-13

Estimate #:

PROJECT CLASSIFICATION: OM&A

PROJECT NUMBER: SABP0053

FACILITY: Pump Generating Station

PROJECT DESCRIPTION: PGS Unit 3 Rehabilitation

Estimated Cost Summary (K$)

Project Components	TOTAL EST.	2013	2014	2015	2016	2017	Future Years	%
Removal Costs								
Contingency	[redacted]							
Interest								
Development Spending								
Execution Phase (Summary)	[redacted]							
Project Management	153	56	97					2.4%
Engineering	32	16	16					0.5%
Materials	[redacted]							
External Purchase Services	[redacted]							
PWU Charges	1,000	330	670					15.8%
TOTAL	6,342	1,995	4,347					1

SUMMARY: Basis of Estimate

Scope:

Rehabilitate the existing PGS Unit 3 runner, including replacing the runner blades, repairing the servomotor, modify and/or replace seals and sealing surfaces, and other minor runner repairs as required. Complete other work on the unit that is consistent with a major overhaul and work consistent with PFCA results. This scope will address the potential oil leak issues that currently exist and provide reliable unit operation for 10 to 15 years.

This estimate is based on information compiled from the PGS Unit 6 overhaul, project SABP0030 with actuals equaling 4,577K and from experienced personnel who worked on and were involved with the PG6 overhaul. The new runner blades will be provided to the project through project # SABP0056, PG3 New Runner Blades.

This RQE value is more than the PGS 6 Rehabilitation cost due to added [redacted] escalation cost per year, an allowance for parts procurement and contingency.

Conditions/Assumptions:

Allowances have been included in the contingencies for work processes that have changed since PGS U 6 was overhauled and also to accommodate a workforce learning curve with the PWU crew, as most are new.

The schedule relies on the NPG machining facility and Alstom providing the required services as shown on the project schedule.

Schedule:

Start Date: Monday, September 16, 2013

Project In-Service Date: Friday, July 11, 2014

Back up documents attached:

- ☐ Contractor Quote
- ☐ Project Schedule
- ☐ Labour Estimate
- ☐ Shop Services Estimate
- ☐ Other (description)
- ☐ Other (description)

Prepared by:

APRIL 11/13

Greg Young — Date

Project Engineer/Officer

Approved by:

Apr. 15/13

Dan Roorda — Date

Section Manager, Projects

Estimate conforms to AACE - Class 3

OPG Governance applicable to the preparation of this document ETS-PM-STD-006; HY-HD-STD-06; OPG-PROC-0050

ONTARIO POWER GENERATION

Niagara Plant Group

RELEASE QUALITY ESTIMATE (RQE)
Summary Sheet (K$)

Date: 18-Apr-13
Estimate #:

PROJECT CLASSIFICATION: CAPITAL
PROJECT NUMBER: SABP0056 **FACILITY:** SAB PGS (NF282)
PROJECT DESCRIPTION: PG3 New Runner Blades

Estimated Cost Summary (K$)

Project Components	TOTAL EST.	2012 LTD	2013	2014	2015	2016	Future Years	%
Removal Costs								
Contingency	[redacted]							
Interest	32		5	20	7			1.2%
Development Spending								
Execution Phase (Summary)	[redacted]							
Project Management	12		12					0.4%
Engineering								
Materials	[redacted]							
External Purchase Services								
PWU Charges								
TOTAL	2,701		424	1,646	631			1

SUMMARY: Basis of Estimate

Scope:

Supply of one set of PGS runner blades to replace capital spare installed on PG3.

Conditions/Assumptions:

This estimate is based on a quotation from Alstom (Rev.2) received Jun.14, 2012. The quotation included options for up to 6 additional sets of blades.

Contingency of [redacted] was included for potential price changes.

Schedule: Start Date: Tuesday, July 02, 2013
Project In-Service Date: Tuesday, March 17, 2015

Back up documents attached:

- ☑ Contractor Quote
- ☐ Project Schedule
- ☐ Labour Estimate
- ☐ Shop Services Estimate
- ☐ Other (description)
- ☐ Other (description)

Prepared by:
Apr. 30/13
Greg Young — Date
Project Engineer/Officer

Approved by:
Apr. 30/2013
Dan Fiorda — Date
Section Manager, Projects

Estimate conforms to AACE - Class 3
OPG Governance applicable to the preparation of this document ETS-PM-STD-006; HY-HD-STD-06; OPG-PROC-0050

Table 1
OM&A Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
Projects ≥ $20M Total Project Cost[1]

Line No.	Project Name	Project Summary Ref. No.	Category	Start Date	In-Service Date	Total Project Cost ($M)	2010 Actual ($M)	2011 Actual ($M)	2012 Actual ($M)	2013 Budget ($M)	2014 Plan ($M)	2015 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Project summaries for the following projects are included in this section of the application											
	Niagara Plant Group and Saunders GS:											
	Niagara Plant Group											
1	Sir Adam Beck Pump GS - Units 1-5 Overhauls	SABP0036	Sustaining	2013	2018	21.3	0.0	0.0	0.0	1.2	4.1	4.5
	Saunders GS											
2	No projects in this category					0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Subtotal - Niagara Plant Group and Saunders GS**					21.3	0.0	0.0	0.0	1.2	4.1	4.5
	Newly Regulated Hydroelectric:											
	Ottawa-St.Lawrence Plant Group[2]											
4	Otto Holden GS - Mechanical/Electrical Unit Overhauls	OTTO0036	Sustaining	2013	2023	36.5	0.0	0.0	0.0	0.1	0.4	4.3
5	Chat Falls GS - Main Dam Concrete Repairs	CHAF0035	Sustaining	2012	2016	20.0	0.0	0.5	3.9	3.6	3.5	4.1
	Central Hydro Plant Group											
6	No projects in this category					0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Northeast Plant Group											
7	No projects in this category					0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Northwest Plant Group											
8	No projects in this category					0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Subtotal - Newly Regulated Hydroelectric**					56.5	0.0	0.5	3.9	3.6	3.9	8.4
10	**Total**					77.8	0.0	0.5	3.9	4.8	7.9	12.9

Notes:
1 Projects with expenditures during Test Period.
2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 2
OM&A Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
Projects $5M - $20M Total Project Cost[1]

Line No.	Project Name	Category	Project Description	Total Project Cost ($M)
	(a)	(b)	(c)	(d)
	Niagara Plant Group and Saunders GS:			
	Niagara Plant Group			
1	Sir Adam Beck 1 - Tailrace Bridge & Piers (SAB10053)	Sustaining	Tailrace Bridge & Piers - Rehabilitate Concrete	17.6
	Saunders GS			
2	R.H. Saunders GS - Repaint Barnhardt Island Bridge (JW NYPA) (SAUN0082)	Regulatory	Sandblast old lead paint and repaint entire bridge	6.2
3	R.H. Saunders GS - Concrete Growth Mitigation (SAUN0096)	Sustaining	Slot cutting around generating units	17.7
4	R.H. Saunders GS - Replace Administration Building window & brick (SAUN0101)	Sustaining	Replace original windows and decaying brick on the administration building	7.5
5	**Subtotal - Niagara Plant Group and Saunders GS**			49.0
	Newly Regulated Hydroelectric:			
	Ottawa-St.Lawrence Plant Group[2]			
6	Barrett Chute GS - Rehab/Repair G1-4 Penstocks (BARC0016)	Sustaining	Rehab Penstocks Envelopes & Transition Areas	5.7
7	Barrett Chute GS - G1-G4 Mechanical/Electrical Unit Overhauls (BARC0038)	Sustaining	Mechanical/Electrical Unit Overhauls G1-4 including G3/4 Oil Lift System	5.0
8	Barrett Chute GS - Upgrade Tailrace Grating (BARC0047)	Sustaining	Upgrade Tailrace Grating to Highway Grade	6.9
9	Barrett Chute GS - Re-insulate Rotor Field Poles G1-G4 (BARC0049)	Sustaining	Re-insulate Rotor Field Poles - G1-4	5.0
10	Des Joachims GS - Mechanical/Electrical Overhauls (DESJ0008)	Sustaining	Turbine - mechanical/electrical overhauls (coord G1, G3, G5 with rewind project, and remaining units with runner replacement), replace cooling coils	15.1
11	Des Joachims GS - Headworks Piers Concrete Repairs (DESJ0033)	Sustaining	Repair Headworks Piers, Gains, Upstream face of North & South Bulkheads	5.6
12	Des Joachims - Re-insulate Rotor Field Poles (DESJ0047)	Sustaining	Re-insulate Rotor Field Poles - All units	10.5
13	Stewartville GS - Mechanical/Electrical Overhauls G1-G5 (STEW0040)	Sustaining	Mechanical/Electrical Unit Overhauls - G1-5	7.7
14	Otto Holden GS - Repair Stop Log Sluice Pier Nosings (OTTO0049)	Sustaining	Repair Stop Log Sluice Pier Nosings	8.1
15	Otto Holden GS - Concrete Mitigation Phase 2 (OTTO0051)	Sustaining	Concrete Mitigation Phase 2 Including Gravity Sections, Headbeams, Headworks Deck & Handrails	14.2
	Central Hydro Plant Group			
16	No projects in this category			0.0
	Northeast Plant Group			
17	Lower Notch GS - G1 Overhaul (LNCH0010)	Sustaining	G1 Major Overhaul	5.8
18	Lower Notch GS - G2 Overhaul (LNCH0014)	Sustaining	G2 Major Overhaul	5.8
	Northwest Plant Group			
19	No projects in this category			0.0
20	**Subtotal - Newly Regulated Hydroelectric**			95.3
21	**Total**			144.3

Notes:
1 Projects with expenditures during Test Period.
2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 3
OM&A Project Listing - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric
Projects < $5M Total Project Cost[1]

Line No.	Project Description	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Niagara Plant Group and Saunders GS:			
	Niagara Plant Group			
1	**Aggregate Total All Projects < $5M**	23	20.9	0.9
	Saunders GS			
2	**Aggregate Total All Projects < $5M**	13	15.0	1.2
3	**Subtotal - Niagara Plant Group and Saunders GS**	36	35.8	1.0
	Newly Regulated Hydroelectric:			
	Ottawa-St.Lawrence Plant Group[2]			
4	**Aggregate Total All Projects < $5M**	24	26.8	1.1
	Central Hydro Plant Group			
5	**Aggregate Total All Projects < $5M**	18	16.1	0.9
	Northeast Plant Group			
6	**Aggregate Total All Projects < $5M**	3	3.1	1.0
	Northwest Plant Group			
7	**Aggregate Total All Projects < $5M**	25	13.8	0.6
8	**Subtotal - Newly Regulated Hydroelectric**	70	59.9	0.9
9	**Total**	106	95.7	0.9

Notes:
1 Projects with expenditures during Test Period.
2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Table 4
OM&A Projects - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric Operations
Listing of Business Case Summaries Filed

Line No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date	Project Stage	BCS Status	BCS Status in EB-2010-0008
	(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:					
	Niagara					
1	SABP0036	Sir Adam Beck Pump GS - Units 1-5 Overhauls (Unit PG3 Overhaul released as project number SABP0053)	May-13	Execution	Partial	N/A
		Saunders GS				
2		No projects in this category				
	Newly Regulated Hydroelectric:					
	Ottawa-St.Lawrence Plant Group[1]					
3	OTTO0036	Otto Holden GS - G1 to G3 Overhauls	N/A	Initiation	N/A	N/A
4	CHAF0035	Chats Falls GS - Main Dam Concrete Restoration	Mar-12	Execution	Execution	N/A
	Central Hydro Plant Group					
5		No projects in this category				
	Northeast Plant Group					
6		No projects in this category				
	Northwest Plant Group					
7		No projects in this category				

Notes:
1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

GROSS REVENUE CHARGE AND OTHER WATER AGREEMENT COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence describes the gross revenue charges ("GRC") that OPG is required to pay the Province of Ontario pursuant to legislative and regulatory requirements. It also includes water rental charges and other water agreement costs payable to other governments, agencies, or companies (Parks Canada, Government of Quebec, St. Lawrence Seaway Management Corporation, Hydro Quebec, H2O Power LP) and funding contributions to the Lake of the Woods Control Board and the Ottawa River Regulation Planning Board (Government of Canada).

2.0 OVERVIEW

The GRC refers to the taxes and charges that are required to be paid by owners of hydroelectric generating stations under Section 92.1 of the *Electricity Act, 1998*. Details pertaining to GRC are available in the legislation and *Ontario Regulation 124/02*, and are unchanged from EB-2010-0008. A condensed description of GRC applicable to the regulated hydroelectric stations is provided in Section 3 below.

Water rental charges and other costs associated with leases, licences, or agreements with other governments, agencies, or companies are described in Section 4. OPG's share of costs for funding of Control Boards is described in Section 5.

The forecast GRC, including other water agreement costs, for the regulated hydroelectric facilities is $328.9M and $347.1M in 2014 and 2015, respectively, and forms part of the test period revenue requirement. Of this total, $253.3M in 2014, and $269.5M in 2015 are related to the Niagara Plant Group and R.H. Saunders, and $75.6M in 2014, and $77.5M in 2015 are related to the newly regulated hydro facilities. Exhibit F1-4-1, Table 1, presents the total of GRC and other water agreement costs for the years 2010 to 2015. Year over year changes in GRC are mostly related to annual changes in production, though the increase during the test period is related to an increase in production attributable to the Niagara Tunnel Project.

3.0 GROSS REVENUE CHARGE ON HYDROELECTRIC GENERATING STATIONS

The GRC consists of a property tax component and a water rental component. All fifty-four of the regulated hydroelectric facilities are subject to the GRC – Property component. Only those facilities where water power leases are held with the Ontario Ministry of Natural Resources are subject to the GRC – Water Rental component. Nineteen of the regulated hydroelectric facilities are not subject to GRC water rentals.

The GRC is determined by multiplying the station's annual energy production by the rate of $40 per MWh (as prescribed by O. Reg. 124/02) and then applying the appropriate GRC property and water rental tax rates. For three of the regulated hydroelectric stations located on the Ottawa River (Otto Holden GS, Des Joachims GS, and Chenaux GS), GRC is calculated based on one-half of each station's annual energy generation, with the other half of production subject to Quebec water rentals as described in Section 4 below. Water transactions with another utility are also included in the determination of the station's annual energy production that is subject to the GRC. (See Ex. G1-1-1 for a discussion of Water Transactions). The GRC property tax rates are graduated through four tiers of production, increasing from 2.5 per cent to 4.5 per cent, 6.0 per cent, and 26.5 per cent, as shown in Chart 1. The GRC water rental rates are fixed at 9.5 per cent.

Chart 1
Gross Revenue Charge Components

Station Production (GWh/yr)	Water Rental Rate (%)	Property Graduated Rate (%)	Total GRC Rate (%)
0 – 50	9.5	2.5	12.0
50 – 400	9.5	4.5	14.0
400 – 700	9.5	6.0	15.5
> 700	9.5	26.5	36.0

The GRC property tax applicable to forty-seven of the fifty-four regulated hydroelectric stations is payable to the OEFC. (Stations subject to subsection 92.1 (2) of the *Electricity Act, 1998.*) The GRC property tax applicable for the other seven regulated hydroelectric stations is payable to the Ontario Minister of Finance. (Stations subject to subsection 92.1 (1) of the *Electricity Act, 1998.*)

The GRC water rentals applicable to the thirty-five regulated hydroelectric sites which are operated under water power leases held with the Ontario Ministry of Natural Resources are payable to the Ontario Minister of Finance, with the exception of a portion of the GRC water rental payable with respect to the Sir Adam Beck Complex which is paid to the Niagara Parks Commission as required by O. Reg. 135/02 under the *Electricity Act, 1998*. (Stations subject to subsection 92.1 (5) and (5.1) of the *Electricity Act, 1998*.)

Ontario Regulation 124/02 allows deductions to GRC for eligible capacity of new, redeveloped, or upgraded stations. OPG is preparing an application to the Ministry of Natural Resources for a GRC deduction pertaining to production increases at the Sir Adam Beck plants as a result of the new Niagara tunnel that commenced operation in March 2013. This deduction has not been included in the calculation of GRC costs presented for the bridge year and test period of this application as the applicability and amount of any such deduction is dependent on Ministry review and approval. The timing of such approval is also uncertain. Until approval is received, generation at the Sir Adam Beck plants remains subject to GRC at the full rate. It is unlikely that a decision from the Ministry of Natural Resources will be received before the end of the bridge year and test periods.

4.0 OTHER WATER AGREEMENT COSTS

In addition to the GRC payable to the OEFC and Ontario Minister of Finance, land rentals are paid to the Ontario Ministry of Natural Resources for Crown Leases or Licences of Occupation associated with the regulated hydroelectric facilities. These nominal rentals are included in the GRC totals presented for each Plant Group in Ex. F1-4-1, Table 1.

Other water rental charges and costs are incurred pursuant to agreements with other government agencies and companies, as described below.

St. Lawrence Seaway Management Corporation Lease Agreement

OPG holds a lease agreement with the St. Lawrence Seaway Management Corporation ("SLSMC") pertaining to the conveyance of water from Lake Erie through the SLSMC's Welland Ship Canal to intakes at Allanburg, where water is withdrawn and diverted to the DeCew Falls plants (Niagara Plant Group) for power generation. Water conveyance charges payable to SLSMC are determined based on the monthly average diversion flow. Annual costs are projected to be about $5M for the test period, assuming that the current rate structure remains in effect. The SLSMC water conveyance costs have been included with the Niagara Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

Parks Canada Water Rentals (Trent-Severn Waterway and Rideau Canal)

The operation of seven of the regulated hydroelectric facilities, located on the Trent River or Rideau Canal (Central Hydro Plant Group), are subject to licences with Parks Canada. Annual water rentals prescribed by these licences are determined similar to the GRC Water Rental rate calculation. Annual station energy production is multiplied by the GRC energy rate ($40/MWh) prescribed in Ontario Regulation 124/02 and then an annual tax rate as prescribed by the Parks Canada licence is applied (9.1 per cent for 2013 and 2014; 9.25 per cent for 2015). The water rental cost for the seven sites is projected to total about $0.5M annually during the test period. The Parks Canada water rental costs have been included with the Central Hydro Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

Government of Quebec Water Rentals

The Governments of Ontario and Quebec ratified an Agreement dated January 2, 1943, pertaining to the development of water power on the Ottawa River. (Reference: *The Ottawa River Water Powers Act, 1943*.) Under terms of this agreement, water rentals are paid to the Government of Quebec based on one-half of station production from the upper three Ottawa River plants, Otto Holden GS, Des Joachims GS, and Chenaux GS (Ottawa-St. Lawrence Plant Group). Rental rates prescribed by the 1943 Agreement were revised by subsequent agreement between the parties for the twenty-five year period from 1993 - 2017. The rental rate applicable for the years from 2010 - 2014 is $25 per average yearly horsepower of energy. The rental rate increases to $30 per average yearly horsepower of energy for 2015. Annual water rental costs for the three Ottawa River plants are projected to be $7.8M in 2014 and $9.4M in 2015. The Quebec water rental costs have been included with the Ottawa-St. Lawrence Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

OPG does not pay water rentals to the Government of Quebec for the fourth Ottawa River plant, Chats Falls GS. Ownership of Chats Falls GS is shared with Hydro Quebec. Water rentals payable to the Government of Quebec are paid by Hydro Quebec, based on one-half of station production. OPG pays GRC (property and water rental components) to Ontario based on one-half of Chats Falls annual production.

Hydro Quebec – Dozois Agreement and Cabonga Diversion Agreement

The Ottawa River Water Powers Act, 1943, prescribed that expenses for works that increase or regulate the flow of the Ottawa River are to be shared by the benefitting parties. Under an agreement with Hydro Quebec ("Dozois Agreement"), OPG shares in operation, maintenance and project refurbishment costs associated with Hydro Quebec's Bourque Dam and the Dozois Reservoir. These facilities enable diversion of water from Quebec to the Ottawa River basin (referred to as the "Cabonga diversion") where benefits from this additional water are realized at OPG's four generating stations on the Ottawa River. Annual costs pertaining to the Dozois Agreement are projected to be about $1.3M for the test period. These costs have been included with the Ottawa-St. Lawrence Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

One-half of the energy produced, that is attributable to the Cabonga diversion water, is returned to Hydro Quebec as per terms of the Cabonga Diversion Agreement. "Cabonga payback" averages about 40 GWh annually and is typically settled by scheduled transfers of energy via the R. H. Saunders interconnection.

Hydro Quebec – Bryson Agreement

Hydro Quebec's Bryson Generating Station is located immediately upstream of OPG's Chenaux GS on the Ottawa River. Raising the Chenaux GS forebay elevation to the maximum level authorized by the *Ottawa River Water Powers Act, 1943*, increases the Bryson GS tailwater elevation, resulting in production losses due to reductions in head. The Bryson Agreement prescribes the methodology for determining the production losses incurred at Bryson GS and the means of settlement. OPG compensates Hydro Quebec financially, with annual payments averaging $20k from 2010 - 2012. These costs have been included with the Ottawa-St. Lawrence Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

H2O Power LP Agreement (Whitedog Falls)

OPG's Whitedog Falls GS (Northwest Plant Group) is located on the Winnipeg River downstream of two power plants (Kenora and Norman Dam) owned and operated by H2O Power LP. Commencement of operation of Whitedog Falls in 1958 raised tailwater elevations at the two upstream generating stations, resulting in energy production losses. Consequently, the two parties at the time, the Hydro-Electric Power Commission of Ontario and the Ontario-Minnesota Pulp and Paper Company Ltd, executed an agreement dated February 27, 1961, whereby the latter was compensated for its losses caused by the former. The agreement was binding on the parties, as well as their successors or assigns, and terminates only when the Kenora and Norman Dam power houses cease to operate permanently. A letter agreement dated November 11, 2002, between OPG and Abitibi-Consolidated Company of Canada (successor companies at that time) defined the methodology for calculation of the financial credit following opening of the Ontario electricity market in May 2002. Monthly Ontario Market energy and demand related charges are applied to the energy and power losses incurred by the Kenora and Norman Dam power plants to determine the monthly financial credit. Costs pertaining to this agreement are projected to be about $0.4M annually during the test period. These costs have been included with the Northwest Plant Group's GRC totals presented in Ex. F1-4-1, Table 1.

5.0 CONTROL BOARD COSTS

OPG shares in costs associated with funding of the Ottawa River Regulation Planning Board and the Lake of the Woods Control Board and their respective Secretariats, as required by legislative agreements. (See Ex. A1-6-1, Section 7.1, and Ex. A1-4-2, Section 5.1.3) OPG's share in costs for the two Boards amounts to about $0.14M annually. These costs have been included in the Ottawa-St. Lawrence Plant Group and Northwest Plant Group totals presented in Ex. F1-4-1, Table 1.

Table 1

Gross Revenue Charge - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	164.6	166.2	156.4	159.8	168.3	179.3
2	**Saunders GS**	87.6	93.2	88.1	83.7	85.0	90.2
3	**Subtotal**	252.2	259.4	244.5	243.5	253.3	269.5
	Newly Regulated Hydroelectric:						
4	**Ottawa-St.Lawrence Plant Group**[1]	24.9	31.9	29.0	31.7	32.3	33.9
5	**Central Hydro Plant Group**	2.0	2.1	1.8	2.1	1.8	2.1
6	**Northeast Plant Group**	9.1	15.2	15.8	19.7	19.6	19.5
7	**Northwest Plant Group**	19.0	18.5	19.0	22.2	21.9	22.1
8	**Subtotal**	54.9	67.7	65.6	75.6	75.6	77.5
9	**Total**	307.1	327.1	310.1	319.1	328.9	347.1

10	**NYPA Water Transactions**[2]	2.4	4.1	0.8	0.3	0.0	0.1

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

2 GRC amounts associated with NYPA Water Transactions are not included in the totals presented above.

COMPARISON OF GROSS REVENUE CHARGE AND OTHER WATER AGREEMENT COSTS – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents period-over-period comparisons of the gross revenue charge ("GRC"), including other water agreement costs, for the regulated hydroelectric facilities for 2010 to 2015.

2.0 OVERVIEW

Ontario Regulation 124/02 (amended by O. Reg. 9/10, filed January 20, 2010) prescribes that the fixed price of $40/MWh be used for determining GRC. This price was effective throughout the historical period (2010 - 2012) and is expected to remain in effect for the bridge year and test period (2013 - 2015).

The total of GRC costs and costs pertaining to other water agreements is presented in Exhibit F1-4-2, Table 1. Forecast and actual costs are compared for the years 2010 to 2015. For the Niagara Plant Group and R.H. Saunders, GRC costs comprise about 98 per cent of the total cost. GRC costs comprise about 86 per cent of the total for the newly regulated hydro plants.

The other water agreement costs included with the Plant Group totals presented in Exhibit F1-4-2, Table 1, consist of:

- Niagara PG - The St. Lawrence Seaway Management Corporation lease costs, pertaining to water conveyance charges for water utilized at DeCew Falls.
- Ottawa-St. Lawrence PG – Government of Quebec water rental costs, Hydro Quebec Dozois Agreement costs pertaining to the Ottawa River plants, Hydro Quebec Bryson Agreement costs, and OPG's share of Ottawa River Regulation Planning Board funding.

- Northwest PG - H2O Power LP Agreement costs associated with energy losses incurred by private generating stations located upstream of Whitedog Falls, and OPG's share of Lake of the Woods Control Board funding.
- Central Hydro PG - Parks Canada water rental costs pertaining to licensed plants on the Trent River and Rideau Canal.
- All Plant Groups except Niagara – Land rentals pertaining to Crown Leases and Licences of Occupation held with the Ontario Ministry of Natural Resources.

GRC is directly dependant on energy production. For the facilities where the energy production forecasts are derived using computer models that convert forecast water availability to forecast energy production using generating unit efficiency ratings and planned outage information, the differences between actual and forecast production that are attributable to changes in natural water conditions will be captured in the Hydroelectric Water Conditions Variance Account. These facilities include the Niagara Plant Group, R.H. Saunders and twenty-one of the newly regulated hydroelectric plants, located on nine river systems (See Ex. E1-1-1, Appendix 1). Changes in GRC associated with these energy variances are included in determining the account balance (See Ex. H1-1-1*).*

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2015 Plan versus 2014 Plan

The year-over-year change of $18.2M in costs between the 2014 Plan and the 2015 Plan is primarily due to differences in the energy production forecasts for the two years. Costs are projected to increase from $328.9M in 2014 to $347.1M in 2015. The energy production forecast plan for 2015 of 32.7 TWh is 1.2 TWh more than the 2014 forecast of 31.4 TWh (Ex. E1-1-2). Government of Quebec water rentals (upper three Ottawa River plants) are expected to increase the Ottawa-St. Lawrence Plant Group cost by about $1.6M in 2015 as a result of a rate increase commencing January 2015.

2014 Plan versus 2013 Budget

The year-over-year change of $9.7M in costs between the 2014 Plan and the 2013 Budget is primarily due to differences in the energy production forecasts for the two years. Regulated hydroelectric production is forecast to increase from 30.9 TWh in 2013 to 31.4 TWh in 2014 (Ex. E1-1-2). Costs are projected to increase from $319.1M in 2013 to $328.9M in 2014. Hydro Quebec Dozois agreement costs are expected to increase the Ottawa-St. Lawrence Plant Group cost by about $0.4M in 2014 due to an increase in the Bourque Dam refurbishment project payment schedule.

4.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget versus 2012 Actual

The difference of $9.1M between the 2013 Budget ($319.1M) and 2012 actual costs ($310.1M) is due to differences between forecast and actual production. The production forecast for the 2013 Budget (30.9 TWh) is 5 per cent higher than actual production of 29.4 TWh achieved during 2012 (Ex. E1-1-2).

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual versus 2012 Board Approved

The difference between 2012 actual costs and the 2012 Plan is primarily due to differences between forecast and actual production. Actual cost for 2012 was $310.1M, $28.6M less than the 2012 Plan of $338.6M. Actual production during 2012 was 29.4 TWh, 2.9 TWh less than the production plan of 32.3 TWh (Ex. E1-1-2).

The reduction in cost due to reduced production for the Ottawa-St. Lawrence Plant Group was partially offset by an increase in costs ($0.8M) associated with the Hydro Quebec Dozois Agreement in 2012. (Annual cost share payments pertaining to the Bourque Dam refurbishment project commenced in 2012.)

2012 Actual versus 2011 Actual

The difference of $17.1M in cost between 2012 and 2011 was primarily due to year-over-year changes in production. Costs decreased from $327.1M in 2011 to $310.1M in 2012. Actual production decreased from 31.0 TWh in 2011 to 29.4 TWh in 2012 (Ex. E1-1-2).

The reduction in cost due to reduced production for the Ottawa-St. Lawrence Plant Group was partially offset by an increase in costs ($0.8M) associated with the Hydro Quebec Dozois Agreement in 2012. (Annual cost share payments pertaining to the Bourque Dam refurbishment project commenced in 2012.)

2011 Actual versus 2011 Board Approved

The difference between actual and plan costs for 2011 was due to changes between forecast and actual production. The plan production for 2011 was 32.3 TWh versus actual production of 31.0 TWh (Ex. E1-1-2). The decrease in production resulted in an $11.5M reduction in costs from $338.6M (plan) to $327.1M (actual).

2011 Actual versus 2010 Actual

The difference in cost between 2011 and 2010 is due to year-over-year changes in production. Actual production increased from 28.9 TWh in 2010 to 31.0 TWh in 2011 (Ex. E1-1-2). Costs increased by $20.0M, from $307.1M in 2010 to $327.1M in 2011.

2010 Actual versus 2010 Budget

The difference in cost between actual and budgeted amounts for 2010 is due to differences between forecast and actual production. The production plan for 2010 was 31.7 TWh versus actual production of 28.9 TWh (Ex. E1-1-2). This difference resulted in a $23.8M decrease in costs, from $331.0M (budgeted) to $307.1M (actual).

Numbers may not add due to rounding.

Table 1

Comparison of Gross Revenue Charge - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved[4]	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Niagara Plant Group**	163.5	1.2	164.6	1.6	162.6	3.6	166.2	(9.8)	156.4
2	**Saunders GS**	93.7	(6.2)	87.6	5.7	94.5	(1.3)	93.2	(5.1)	88.1
3	**Adjustment per EB-2010-0008 Decision**					6.6	(6.6)			
4	**Subtotal**	257.2	(5.0)	252.2	7.2	263.7	(4.3)	259.4	(14.9)	244.5
	Newly Regulated Hydroelectric:									
5	**Ottawa-St.Lawrence Plant Group[1]**	31.1	(6.2)	24.9	7.1	31.1	0.9	31.9	(3.0)	29.0
6	**Central Hydro Plant Group**	2.1	(0.1)	2.0	0.1	2.2	(0.1)	2.1	(0.3)	1.8
7	**Northeast Plant Group**	18.5	(9.4)	9.1	6.1	19.8	(4.6)	15.2	0.5	15.8
8	**Northwest Plant Group**	22.0	(3.0)	19.0	(0.5)	21.8	(3.4)	18.5	0.6	19.0
9	**Subtotal**	73.8	(18.8)	54.9	12.8	74.9	(7.2)	67.7	(2.1)	65.6
10	**Total**	331.0	(23.8)	307.1	20.0	338.6	(11.5)	327.1	(17.1)	310.1
11	**NYPA Water Transactions[6]**	6.0	(3.6)	2.4	1.7	5.5	(1.4)	4.1	(3.2)	0.8

Line No.	Prescribed Facility	2012 Board Approved[5]	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
12	**Niagara Plant Group**	157.9	(1.5)	156.4	3.4	159.8	8.5	168.3	11.1	179.3
13	**Saunders GS**	94.3	(6.3)	88.1	(4.4)	83.7	1.3	85.0	5.2	90.2
14	**Adjustment per EB-2010-0008 Decision**	11.5	(11.5)							
15	**Subtotal**	263.7	(19.3)	244.5	(1.0)	243.5	9.8	253.3	16.3	269.5
	Newly Regulated Hydroelectric:									
16	**Ottawa-St.Lawrence Plant Group[1]**	31.1	(2.2)	29.0	2.7	31.7	0.5	32.3	1.6	33.9
17	**Central Hydro Plant Group[2]**	2.3	(0.5)	1.8	0.3	2.1	(0.3)	1.8	0.2	2.1
18	**Northeast Plant Group**	19.9	(4.1)	15.8	3.9	19.7	(0.1)	19.6	(0.1)	19.5
19	**Northwest Plant Group[3]**	21.6	(2.5)	19.0	3.1	22.2	(0.2)	21.9	0.2	22.1
20	**Subtotal**	74.9	(9.3)	65.6	10.1	75.6	(0.0)	75.6	1.9	77.5
21	**Total**	338.6	(28.6)	310.1	9.1	319.1	9.7	328.9	18.2	347.1
22	**NYPA Water Transactions[6]**	5.0	(4.1)	0.8	(0.5)	0.3	(0.3)	0.0	0.1	0.1

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e., Saunders GS costs are excluded.
Costs pertaining to Quebec water rentals, Hydro Quebec Dozois Agreement and Bryson Agreement are included with the GRC costs.

2 Central Hydro PG values include Parks Canada water rental costs.

3 Northwest PG values include H2O Power LP (Whitedog Falls) Agreement costs.

4 For Newly Regulated Hydroelectric, 2011 Budget is provided rather than 2011 Board Approved, as these assets were not regulated in EB-2010-0008.

5 For Newly Regulated Hydroelectric, 2012 Budget is provided rather than 2012 Board Approved, as these assets were not regulated in EB-2010-0008.

6 GRC amounts associated with NYPA Water Transactions are not included in the totals presented above.

OM&A PURCHASED SERVICES – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the purchases of OM&A services and products for the regulated hydroelectric facilities that meet the threshold of 1 per cent of total OM&A expense before taxes consistent with the OEB's filing guidelines.

2.0 OVERVIEW

An overview of OPG's procurement process is presented in Ex. F3-T3-S1.

The regulated hydroelectric OM&A expense before taxes is equal to the sum of the regulated hydroelectric base OM&A plus project OM&A expense. As shown in Ex. F1-1-1, Table 1, and excluding the extraordinary credit of $19M related to the reversal of the provision for the environmental cleanup of Lake Gibson in 2011, this amount ranges from $64.7M in 2010 to a high of $88.0M in 2014 for the Niagara Plant Group and R.H. Saunders GS. As shown in Ex. F1-1-1 Table 2, for the newly regulated stations, the amount ranges from $129.2M in 2013 to $145.9M in 2015. The average annual OM&A expenses of the two regulated hydroelectric segments (i.e. Niagara PG and Saunders GS, and the newly regulated stations) is approximately $100M. Therefore, for the regulated hydroelectric facilities, the threshold of 1 per cent of the OM&A expense before taxes is approximately $1.0M.

Information on vendor contracts for OM&A purchased services within the regulated hydroelectric business that are equal to or in excess of the $1.0M threshold for any of the years 2010, 2011 and 2012 is presented in Chart 1.

Chart 1
Purchase of Services – Regulated Hydroelectric OM&A Contracts

Vendor Name	Description/Nature of Activities	Tendering Process		Rationale if Single Source
		Competitive	Single Source	
HATCH LTD	Wide range of Mechanical, Civil and Electrical Engineering services	✓		
Charles Jones Industrial Limited	Commodity contractor for the supply of tools and shop equipment.	✓		
E.S. Fox	Wide range of construction activities including refurbishment of stop logs and gates, electrical upgrades, parking lot work, and refurbishment of washrooms in Niagara, as well as road work, and piping in NW, and stya vane modifications at Chat Falls,	✓		
Newman Brothers LTD	Wide range of construction activities at Niagara plant group, including, transformer removal, drain work, cliff stabilization, road repair and widening, fore bay cleanout, tailrace deck repair, screenhouse wall repair, and gantry crane work.	✓		
M Sullivan and Sons Limited	Provide a wide range of construction services in the Ottawa St Lawrence and Central plant groups including road work, safety systems, powerhouse maintenance, penstocks, lighting, and turbine overhaul support	✓		
Leo Alarie & Sons LTD	Provide a wide range of construction services, including Matabichuan slope stabilization	✓		
Farrow Construction Company Limited	Provides a range of construction services, primarily concrete work on plants in NW plant group	✓		

Voith Hydro Inc	Provides replacement products and service support for both hydro turbines and generators	✓		
Flynn Canada LTD	Provides labour, materials, tools and equipment to replace powerhouse roofing	✓		
Rankin Construction INC.	Provides wide range of construction and concrete repairs to NPG	✓		
The State Group Inc.	Supplier of multi trade mechanical, electrical and civil services	✓		
Nor Eng Construction & Engineering Inc	Provides a wide range of construction services, including Bark Lake Dam refurbishment	✓		
The Barclay Construction Group Inc	Provides a wide range of construction services, including the Matabichuan penstock	✓		
Peter Kiewit Infrastructure Co	Provides a wide range of construction services, including the Manitou Falls pier and headwork repair	✓		
DJ Venassse Construction Inc	Provides a wide range of construction services, including concrete repair and public safety fencing in Central Plant Group,	✓		
GDB Constructeurs 1468792 Ontario Inc	Provides a wide range of construction services, including major concrete rehabilitation work at Chats Falls	✓		

Total 2010 Spend ($M) = 31.9
Total 2011 Spend ($M) = 20.9
Total 2012 Spend ($M) = 21.6