

1 **BUSINESS PLANNING AND BENCHMARKING -**
2 **REGULATED HYDROELECTRIC**

3
4 **1.0 PURPOSE**

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

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8 **2.0 OVERVIEW**

9 A summary of the operating costs that form part of the regulated hydroelectric revenue
10 requirement is presented in Ex. F1-T1-S1 Table 1. The regulated hydroelectric forecasts
11 for the test period are from OPG's 2010 - 2014 business plan for the regulated
12 hydroelectric facilities. Section 3.0 presents the regulated hydroelectric performance
13 targets and section 4.0 presents the regulated hydroelectric benchmarking results.

14
15 The Hydroelectric business plan is prepared annually as part of the corporate business
16 planning and budgeting process described in Ex. A2-T2-S1. The Hydroelectric business
17 planning process is focused on identifying the initiatives and resources required to
18 achieve safety, operational, financial, and new development objectives for the
19 hydroelectric business. These business unit objectives, described in section 3 of Ex. A1-
20 T4-S2, are consistent with OPG's mandate and corporate objectives.

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22 The 2010 - 2014 Hydroelectric business plan as it relates to the regulated hydroelectric
23 facilities is provided in Attachment 1. Discussion of specific initiatives contained in the
24 business plan and their impact on operational and financial performance can be found in
25 the evidence on base OM&A (Ex. F1-T2-S1), project OM&A (Ex. F1-T3-S1), capital
26 projects (Ex. D1-T1-S1), and the production forecast (Ex. E1-T1-S1).

27
28 The Hydroelectric business planning process begins in early May of each year with
29 internal reviews of the current planning framework, the confirmation and updating of
30 business objectives and priorities, a review of business planning instructions from

1 Finance, a review of the status of operational and performance plans and related capital
2 and OM&A expenditures, a review of benchmarking “best practices” and comparisons,
3 and the identification of emerging issues. Out of this process, strategic and performance
4 objectives and guidelines for Hydroelectric are determined, prioritized and finalized.

5
6 OM&A and capital guidelines are established for each plant and central office group in
7 May. The starting point for the guidelines is based on the previous year’s business plan.
8 In response to the poor financial environment expected going forward and to align with
9 the 2010 corporate cost reduction objectives, plant and central office groups were
10 directed to be aggressive in managing their costs while maintaining their critical safety,
11 environmental, and performance objectives. The Hydroelectric business was asked to
12 contribute \$5M to the overall OPG cost reduction target of \$85M described in Ex. A2-T2-
13 S1. The regulated stations were allocated \$1.2M (25 per cent) of the total \$5M
14 Hydroelectric cost reduction.

15
16 A business planning meeting is held in mid-May with asset management and finance
17 stakeholders from each plant group and central office groups, and certain corporate
18 groups. The 2010 - 2014 meeting agenda included corporate planning context and
19 financial challenges, business planning schedule, Hydroelectric financial guidelines and
20 cost reduction initiatives, staffing initiatives to address demographic and emerging work
21 requirements, energy production and outage planning, and review of the Hydroelectric
22 portfolio management system and corporate risk management process. The key
23 business planning issues are also discussed at the monthly Hydroelectric Management
24 Team meetings in May through October.

25
26 The plant and central office groups develop their detailed business plans during
27 June/July, and submit them to the Executive Vice President Hydroelectric (“EVP –
28 Hydroelectric”) at the end of July. The Business Support and Regulatory Affairs Division
29 performs a thorough review and challenge of each business plan. The business plans
30 are consolidated into a preliminary Hydroelectric Business Plan for review by the EVP -
31 Hydroelectric in early August. Redirection is provided to specific plant groups as

1 required. A formal review meeting is subsequently held at each plant group location
2 where the local plant group management presents their business plan to the EVP -
3 Hydroelectric and members of the Hydroelectric Management Team for preliminary
4 approval. The preliminary Hydroelectric Business Plan is then modified as required and
5 submitted for review by the President and Chief Executive Officer (“CEO”), and the Chief
6 Financial Officer (“CFO”). Changes are made per the direction of the CEO (if required)
7 prior to its final submission to the OPG Board of Directors, as discussed at Ex A2-T2-S1.
8

9 The key approaches used to identify and prioritize investment and base work program
10 requirements in support of regulated hydroelectric’s objectives are described below.
11

12 Portfolio Approach to Investment Management

13 Hydroelectric uses a structured portfolio approach to identify and prioritize projects for its
14 investment program. Annual engineering reviews and plant condition assessments
15 (conducted on a cycle of approximately seven to ten years) are performed to determine
16 short-term and long-term expenditure requirements to sustain or improve each facility,
17 and ensure continued safe operation. These may be followed by the preparation of a
18 facility life cycle plan, which is performed on an as-needed basis for marginal assets or
19 assets requiring significant expenditures relative to the value of the facility. This planning
20 approach is designed to identify necessary capital, operating and maintenance
21 expenditures for each facility, and direct limited corporate funds at the facilities that can
22 best maintain or enhance the value of the hydroelectric business and OPG. The
23 cornerstone of this approach is that safety, environmental, and other regulatory
24 programs are of the highest priority compared to production and reliability initiatives.
25

26 Streamlined Reliability Centred Maintenance Process

27 Hydroelectric uses a process known as streamlined reliability centred maintenance
28 process to optimize the preventive maintenance program at its facilities. The streamlined
29 reliability centred maintenance process provides a consistent method of identifying,
30 scheduling and executing maintenance activities. The concept of streamlined reliability
31 centred maintenance dictates that the type and frequency of preventive maintenance

1 applied to an individual component is determined based on the nature and
2 consequences of failure (i.e., balance of cost versus risk). By focusing maintenance and
3 associated support resources appropriately, Hydroelectric has been able to accomplish
4 more of its base work program (including additional regulatory requirements), while
5 minimizing the need for additional resources.

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7 **3.0 HYDROELECTRIC KEY PERFORMANCE TARGETS**

8 Hydroelectric establishes performance targets to support its business objectives as part
9 of the business planning process. Benchmarking, as discussed in section 4.0, is one tool
10 used in target setting and Hydroelectric generally benchmarks its performance against
11 these targets.

12

13 Hydroelectric performance targets are established on the basis of the following factors:

- 14 • Historical performance trends
- 15 • Age and condition of facilities
- 16 • Major outages and project investments (OM&A and capital) identified in inspections,
17 engineering reviews and plant condition assessments
- 18 • Recent major investments to improve reliability
- 19 • Comparison with external benchmarking results and “best practices”
- 20 • Continuous improvement considerations

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22 Targets are monitored and compared to actual data as the year progresses. Targets are
23 established for the following measures:

24

25 Availability

26 Availability is a measure of the reliability of a generating unit represented by the
27 percentage of time the unit is capable of providing service, whether or not it is actually
28 in-service, relative to the total hours for the period in question (typically 8,760 hours in a
29 year). It is determined by the following equation: Availability = 100 per cent – Incapability
30 Factor (“ICbF”), where ICbF is a measure of the incapability of a unit to generate over

1 the period in question. Incapability factor is defined as the ratio of scheduled and
2 unscheduled outage hours and adjusted derating hours to the total hours in the period.

3
4 Equivalent Forced Outage Rate

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

9
10 OM&A Unit Energy Cost

11 OM&A unit energy cost measures the cost effectiveness of the hydroelectric generating
12 stations. It is defined as total hydroelectric OM&A expense plus allocated central
13 hydroelectric costs, divided by hydroelectric electricity generation. The gross revenue
14 charge (“GRC”) is excluded from this calculation because it is not within the direct
15 control of OPG. The GRC is determined by O. Reg. 124/02 under the *Electricity Act*,
16 1998 and is a function of energy produced and the price set by the Provincial
17 Government.

18
19 Safety – Accident Severity Rate

20 OPG and the Hydroelectric Business Unit spend a significant amount of time and effort
21 in training and awareness to ensure the safety of its employees. The accident severity
22 rate is used as a key measure of safety performance both within Hydroelectric and
23 across OPG. It is defined as the number of days lost by employees injured on the job
24 divided by 200,000 hours worked. This measure is used by other electric utilities and is
25 benchmarked by the Canadian Electrical Association (“CEA”).

26
27 Environmental Performance

28 Hydroelectric uses an environmental performance index to measure the environmental
29 performance of the regulated facilities. The environmental performance index consists of
30 three main categories:

- 31 • Spills

- 1 • Regulatory compliance (e.g., regulatory infractions)
- 2 • Energy efficiency

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4 **3.1 Performance Targets**

5 3.1.1 Availability and Equivalent Forced Outage Rate (“EFOR”) - History and Targets

6 Chart 1 shows reliability targets and actual performance from 2007 - 2009 for each
7 regulated plant and for the total of the regulated plants grouped together. Chart 2a and
8 2b show availability and EFOR targets, respectively from 2010 - 2012 calculated on the
9 same basis as Chart 1. As part of the general objective of continuous improvement, the
10 EFOR target of 1.3 per cent for 2010 - 2012 represents an improvement from the five
11 year average of 1.4 per cent. The targets are better than the CEA and EUCG Inc.
12 (formerly known as Electric Utility Cost Group) benchmarking averages. Availability
13 targets fluctuate based on the planned outage program, as well as forced outages which
14 cannot be predicted. In 2009, availability was better than target due to the deferral of
15 some planned outages at DeCew Falls II, Sir Adam Beck I and Sir Adam Beck Pump
16 Generating Station (“PGS”). Overall, availability is expected to improve in the long-run
17 (after 2014) as the major outages for frequency conversions/rehabilitations of Sir Adam
18 Beck I are completed.

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Chart 1

Regulated Hydroelectric Facilities - History and Targets for Availability and EFOR

| Measure | Name of Station/Grouping | 2007 Target | 2007 Actual | 2008 Target | 2008 Actual | 2009 Target | 2009 Actual | Notes |
|--------------------------------|---|---|-------------|-------------|-------------|-------------|-------------|--|
| Availability Factor (%) | DeCew Falls II | 75.1 | 77.6 | 93.4 | 96.9 | 91.8 | 97.3 | Major outage and overhaul in 2007. |
| | SAB I | 93.9 | 92.3 | 95.0 | 92.7 | 82.9 | 89.1 | Major rehabilitation outages include G7 in 2008/2009 & G9 in 2009/2010. |
| | SAB II | 96.0 | 96.9 | 96.9 | 97.4 | 97.0 | 96.7 | Station rehabilitated and upgraded from 1996 to 2005. |
| | SAB PGS | 89.7 | 86.1 | 81.1 | 79.2 | 77.8 | 84.5 | Major unplanned rehab of G6 required in 2008/2009 due to small oil leak in turbine. The G3 unit outage was deferred in 2009 to perform detailed condition assessment.. |
| | Saunders | 95.3 | 97.3 | 96.4 | 95.8 | 96.4 | 95.7 | Station rehabilitated and upgraded from 1992 to 2001. |
| | Aggregate of all 5 regulated plants (excl. DeCew Falls I) | 93.8 | 94.1 | 94.4 | 93.8 | 92.7 | 93.6 | |
| EFOR (%) (Reliability) | DeCew Falls II | 1.1 | 1.0 | 1.1 | 0.8 | 1.1 | 0.2 | |
| | SAB I | 2.0 | 3.7 | 2.0 | 4.3 | 2.0 | 2.3 | Unit 9 was on a permanent derating until rehab start in 2009 |
| | SAB II | 0.5 | 0.4 | 0.5 | 0.2 | 0.5 | 0.6 | EFOR in 2009 increased due to defective main transformer bushings. |
| | SAB PGS | 3.5 | 9.7 | 3.5 | 2.7 | 3.5 | 4.4 | |
| | Saunders | 0.6 | 0.0 | 0.6 | 1.1 | 0.6 | 0.1 | |
| | | Aggregate of all 5 regulated plants (excl. DeCew Falls I) | 1.1 | 1.8 | 1.2 | 1.5 | 1.2 | 1.0 |

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Notes:

- High availability factor is good and low EFOR is good.
- The availability and EFOR of DeCew Falls I is not tracked since this is a “supplementary” station that basically utilizes the available water that is in excess of what can be utilized by the newer and more efficient DeCew Falls II station.
- The aggregate figures are calculated as a capacity-weighted average.

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Chart 2a
Availability Targets (%)

| | SAB I | SAB II | SAB PGS | DeCew Falls II | Total Niagara | Saunders | Total |
|------|--------------|---------------|--------------------|---------------------------|--------------------------|-----------------|--------------|
| 2010 | 79.3 | 95.3 | 82.3 | 90.2 | 88.7 | 93.7 | 90.4 |
| 2011 | 84.2 | 96.6 | 76.3 | 93.2 | 89.5 | 94.2 | 91.1 |
| 2012 | 80.2 | 97.7 | 72.5 | 93.6 | 88.3 | 96.1 | 90.9 |

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The "Total" column presents a capacity-weighted average of the five plants shown.

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Chart 2b
EFOR Targets (%)

| | SAB I | SAB II | SAB PGS | DeCew Falls II | Total Niagara | Saunders | Total |
|------|--------------|---------------|--------------------|---------------------------|--------------------------|-----------------|--------------|
| 2010 | 3.5 | 0.2 | 4.8 | 2.6 | 1.8 | 0.4 | 1.3 |
| 2011 | 3.5 | 0.2 | 4.8 | 2.6 | 1.8 | 0.4 | 1.3 |
| 2012 | 3.5 | 0.2 | 4.8 | 2.6 | 1.8 | 0.4 | 1.3 |

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The "Total" column presents a capacity-weighted average of the five plants shown.

13 **3.1.2 OM&A Unit Energy Cost - History and Targets**

14 Chart 2c shows OM&A unit energy cost targets for 2007 - 2012. These targets are
 15 calculated using planned OM&A expenditures (per business plan process described
 16 above) divided by the energy forecast for each year. From 2007 - 2009, the actual
 17 performance was better than target for both Niagara and R.H. Saunders mostly due to
 18 higher than expected energy production from higher water inflows. Future unit energy
 19 cost targets are in line with historical figures except in 2011 when increases in OM&A

1 expenditures for divestiture of bridges in Niagara and certain OM&A projects at R.H.
 2 Saunders increase the target slightly above historical levels.

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Chart 2c
OM&A Unit Energy Cost Targets (\$/MWh)

| | Niagara Total | Saunders | Total |
|--------------|----------------------|-----------------|--------------|
| 2007 Targets | 4.4 | 2.5 | 3.7 |
| 2007 Actuals | 3.9 | 2.1 | 3.2 |
| 2008 Targets | 4.7 | 2.7 | 4.0 |
| 2008 Actuals | 4.6 | 2.7 | 3.9 |
| 2009 Targets | 4.5 | 2.6 | 3.8 |
| 2009 Actuals | 4.6 | 2.3 | 3.7 |
| 2010 Targets | 4.2 | 2.3 | 3.5 |
| 2011 Targets | 4.9 | 2.6 | 4.1 |
| 2012 Targets | 4.4 | 2.8 | 3.8 |

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3.1.3 Safety - Accident Severity Rate - History and Targets

Chart 2d shows the accident severity rate actual performance and targets for 2007 - 2012. These targets are based on CEA and other benchmarking, as well as OPG's overall targets. It is important to note that the accident severity rate has been zero days lost/200,000 hours worked at Niagara Plant Group for the past six years and zero days lost/200,000 hours worked at R.H. Saunders for the past 11 years. This is excellent performance by any standard.

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Chart 2d
Accident Severity Rate (number of days lost/200,000 hours worked)

| | Total Niagara | Saunders | Total |
|----------------------------|----------------------|-----------------|--------------|
| 2007 through 2009 (actual) | 0 | 0 | 0 |
| 2010 through 2012 (target) | <4.5 | <4.5 | <4.5 |

3.1.4 Environmental Performance Index – History and Targets

Hydroelectric has a very good track record with regard to environmental performance. Environmental management systems have been in place since 2000 and are registered under the International Organization of Standardization (“ISO”) 14001. The ISO 14001 registration ensures compliance with legal requirements and continual improvement of the environmental management system. Hydroelectric also has a number of environmental programs in place to manage priority environmental issues and risks.

In 2009, the Niagara Plant Group was designated as an Environmental Leader by the Ontario Ministry of Environment (“MOE”). They were the first group in the electricity sector to be designated as an Environmental Leader. The Niagara Plant Group has also been recognized and certified by the Wildlife Habitat Council over the past four years for their various biodiversity programs. R.H. Saunders also received certification for their biodiversity initiatives by the Wildlife Habitat Council. In 2009, the eel ladder at R.H. Saunders was modified and improved by adding: a 300 metre extension upstream, a new surface that helps eels climb the ladder faster, and a cover for the ladder.

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 enhancements (such as energy efficiency). 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 regulated facilities, the actual EPI has been

1 better than the target of 1.0 from 2007 to 2009. The EPI target for 2010 - 2012 continues
2 to be 1.0.

3 4 **4.0 REGULATED HYDROELECTRIC FACILITIES BENCHMARKING**

5 Hydroelectric benchmarks reliability, cost and safety performance with comparable
6 businesses to assess and understand the performance of its stations, as well as to
7 identify and share best practices and opportunities for improvement.

8
9 Benchmarking data provides a starting point to compare the costs and reliability of
10 OPG's regulated hydroelectric facilities to those of other hydroelectric facility owners.
11 Because of the differing geographic locations and distribution of the plants, as well as
12 differences in regulatory regimes, absolute comparisons cannot be made directly
13 between the regulated hydroelectric station costs and those of other utilities. In addition,
14 the following factors can result in differences in cost and reliability benchmarking
15 comparisons that cannot be explained or corrected through differences in best practices:

- 16 • Specifics of a station's design, unit size and site configuration
- 17 • The number of, type of and physical dimensions of its dams
- 18 • The way the station has historically been operated and maintained
- 19 • The station/equipment age and condition
- 20 • Water conditions (i.e., flows and water levels) and the resulting production

21
22 For these reasons, benchmarking results for individual plants should only be used as a
23 guide in making comparisons and to determine best practices towards the goal of
24 achieving continuous improvement and cost efficiencies.

25
26 Hydroelectric reviews benchmarking results and best practices annually as part of the
27 business planning process described earlier in this exhibit and applies any new practices
28 and associated cost reductions as appropriate. Hydroelectric also has participated in
29 informal benchmarking activities with various utilities in the past to identify actions that
30 ultimately may result in costs efficiencies, and operational and maintenance
31 improvements. During the past ten years, Hydroelectric has incorporated best practices

1 that have resulted in cost savings. These savings continue to be embedded in future
2 base OM&A business plans and budgets. Examples of best practices that have been
3 implemented include:

- 4 • Consolidation of operating centres
- 5 • Station automation
- 6 • Use of risk-based versus time-based maintenance approach (streamlined reliability-
7 centred maintenance)
- 8 • Overtime reductions from 15 per cent of labour cost (in 2001) to under 6 per cent (in
9 2009)
- 10 • Skill broadening (trades learn more than one discipline)
- 11 • Implementation of “lead plant” concept in 2002 (for details, see Ex. A1-T4-S2)

12
13 Hydroelectric uses three main sources for benchmarking:

- 14 • EUCG Inc. (“EUCG”, formerly known as Electric Utility Cost Group)
- 15 • Canadian Electrical Association (“CEA”)
- 16 • Navigant Consulting (which acquired Haddon Jackson Associates, specialists in
17 hydroelectric benchmarking, in 2007). Hydroelectric staff also attend a Benchmarking
18 Review and Best Practices Workshop held by Navigant Consulting annually

19
20 EUCG and CEA Reliability Benchmarking

21 Hydroelectric has participated in the Generation Equipment Reliability Information
22 System benchmarking programs carried out by the EUCG and the CEA since the mid
23 1990s. EUCG benchmarking includes participation by Canadian and American utilities,
24 including Manitoba Hydro, New Brunswick Power, Pacific Gas & Electric, U.S. Army
25 Corps of Engineers, Tennessee Valley Authority, Seattle City and Light, and Bonneville
26 Power Authority. For this benchmarking, the data are not aggregated, thus individual
27 OPG plants can be compared to the individual plants in the entire group (i.e., “quartile”
28 analysis can be done). Nine Canadian utilities participate in the CEA benchmarking,
29 including Hydro-Quebec, Manitoba Hydro, BC Hydro, Churchill Falls, Newfoundland and
30 Labrador Hydro, Nova Scotia Power, Saskatchewan Power, Alcan and Aquila. The CEA

1 benchmarking is done on an aggregate basis by utility. OPG plants (aggregated) are
 2 compared to the aggregate of the plants in the entire group of utilities.

3
 4 Benchmarking results for reliability, cost and safety are presented below.

5
 6 **4.1 Equivalent Forced Outage Rate and Availability**

7 Hydroelectric benchmarks the reliability indicators of Equipment Forced Outage Rate
 8 (“EFOR”) and availability using data from the EUCG and CEA. The results of the 2006 -
 9 2009 reliability benchmarking of the regulated hydroelectric facilities are presented in the
 10 two charts below.

11 **Chart 3a**
 12 **EUCG Reliability Benchmarking**

13

| Measure | Name of Station/ Grouping | Value In 2006 & Quartile | Value In 2007 & Quartile | Value In 2008 & Quartile | Value In 2009 (EUCG Benchmarking Not Available) |
|--|------------------------------|-----------------------------|-----------------------------|-----------------------------|--|
| Availability Factor (%) | DeCew Falls II | 64.4 (Q4) | 77.6 (Q4) | 96.9 (Q1) | 97.3 |
| | SAB I | 91.8 (Q2) | 92.3 (Q2) | 92.7 (Q2) | 89.1 |
| | SAB II | 97.3 (Q1) | 96.9 (Q1) | 97.4 (Q1) | 96.7 |
| | SAB PGS | 90.7 (Q3) | 86.1 (Q4) | 79.2 (Q4) | 84.5 |
| | Saunders | 97.4 (Q1) | 97.3 (Q1) | 95.8 (Q2) | 95.7 |
| Equivalent Forced Outage Rate (Reliability) (%) | DeCew Falls II | 17.2 (Q4) | 1.0 (Q3) | 0.8 (Q2) | 0.2 |
| | SAB I | 3.2 (Q3) | 3.7 (Q3) | 4.3 (Q3) | 2.3 |
| | SAB II | 0.1 (Q1) | 0.4 (Q1) | 0.2 (Q1) | 0.6 |
| | SAB PGS | 2.0 (Q3) | 9.7 (Q4) | 2.7 (Q3) | 4.4 |
| | Saunders | 0.0 (Q1) | 0.0 (Q1) | 1.1 (Q3) | 0.1 |

14
 15 Notes:

- 16 • EUCG includes 244 stations/925 units.
 17 • High availability is good and low forced outage rate is good.
 18 • Q1 means that a station is in the top/best quartile of the benchmarked EUCG stations.

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Chart 3b
CEA Reliability Benchmarking

| Measure | Name of Station/Grouping | Value In 2006 | Value In 2007 | Value In 2008 | Value In 2009 |
|--|--|----------------------|----------------------|----------------------|----------------------|
| Availability Factor (%) | Availability CEA (excluding OPG) | 89.6 | 91.3 | Not Available | Not Available |
| | Aggregate of all 5 OPG large plants (including Beck PGS) | 94.2 | 94.1 | 93.8 | 93.6 |
| Equivalent Forced Outage Rate (Reliability) (%) | Forced Outage Rate CEA (excluding OPG) | 2.7 | 3.3 | Not Available | Not Available |
| | Aggregate of all 5 OPG large plants (including Beck PGS) | 1.5 | 1.8 | 1.5 | 1.0 |

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Notes:

- CEA benchmarking includes 692 generating units.
- High availability is good and low EFOR is good.

9 The above data demonstrates that the availability and reliability for the individual
 10 regulated facilities and the regulated facilities in aggregate, is generally better than (i.e.,
 11 in upper two quartiles) the EUCG and CEA benchmarks. Sir Adam Beck PGS is included
 12 in the OPG data for completeness. This station is inherently less reliable than
 13 conventional hydroelectric and the newer, higher capacity pumped storage stations, due
 14 to its older, technically complex, reversible pump turbine design, and its multi-faceted
 15 role in the electricity system (e.g., pumping, generation, automatic generation control,
 16 and water diversion control). To accomplish this role, more frequent stops and starts are
 17 required than conventional stations, leading to more wear and tear on the equipment.

1 The two largest plants, Sir Adam Beck II and R.H. Saunders, were generally in the upper
2 two quartiles for both availability and EFOR from 2006 - 2008. The Sir Adam Beck II's
3 EFOR from 2006 - 2008 ranged between 0.1 per cent and 0.4 per cent and was in the
4 top quartile in each year, which constitutes excellent performance. The performance of
5 R.H. Saunders has generally been very good during the 2006 - 2008 period, but in 2008
6 the EFOR deteriorated to 1.1 per cent (third quartile) due to a generator failure of Unit
7 G8. The availability in 2008 was still very good at 95.8 per cent (second quartile). In
8 2009 availability remained high, and the EFOR returned to exceptionally low level of 0.1
9 per cent.

10
11 In 2006 and 2007, DeCew Falls II had below average availability performance due to
12 long planned outages to rehabilitate the two units and improve performance. The outage
13 program started in 2005 and was completed in 2007. The reliability of this station
14 improved in 2008 and 2009 as expected. The availability has improved from 77.6 per
15 cent (Q4) in 2007 to 96.9 per cent (Q1) in 2008 and 97.3 per cent in 2009. The EFOR
16 has also significantly improved from the poor level experienced in 2006 as the
17 operational problems, which were prevalent from 2000 - 2006, were corrected by the
18 overhauls performed in 2006 and 2007.

19
20 With regard to Sir Adam Beck I, performance is below average (especially EFOR) for its
21 peer group due to the age and poor condition of most of the units. Rehabilitation of the
22 Sir Adam Beck I units was started in 2007 when Unit G7 was rehabilitated, upgraded
23 and converted from 25 to 60 Hz. This major work was successfully completed in mid-
24 2009. The remaining two 25 Hz units and the frequency converter have been
25 permanently shut down with the end of the 25 Hz system in the Niagara/Hamilton
26 Region. The rehabilitation at Sir Adam Beck I units continues with Unit G9, which was
27 derated for several years. Unit G9 was removed from service in mid-2009. The reliability
28 of the station is expected to improve after the remaining operating units are rehabilitated
29 and upgraded.

1 Sir Adam Beck PGS's availability and reliability has generally been in the third and fourth
2 quartiles between 2006 and 2008. Since the station is unique in its technical design,
3 vintage and role, there are no real comparators in the EUCG database for PGS. The
4 reliability comparisons with the rest of the EUCG stations have been included in the
5 chart above for information purposes only. In 2006, Sir Adam Beck PGS's availability
6 (90.7 per cent) was reasonable and the EFOR (2.0 per cent) was very good. However,
7 availability and EFOR deteriorated in 2007 and 2008. This was due to the failure of the
8 governor oil pumps on Unit 4, and leaks in the servo/governor oil system and main shaft
9 of Unit 6 (an environmental, not operational issue). In-situ weld repairs and other repairs
10 were attempted but not successful due to the difficult location of the leakage. Due to the
11 complexity of the unit, and inability to perform repairs in-situ, the unit was dismantled
12 and shipped to the manufacturer's facility in Montreal. The repairs and design
13 improvements took over ten months to complete causing a significant reduction in
14 availability, and increase in EFOR. The unit returned to service in March 2009, and its
15 environmental and operational performance has been excellent.

16

17 As described above, availability targets are based on each individual station's outage
18 plan and the five-year average EFOR. The overall EFOR target of 1.3 per cent for the
19 regulated hydroelectric stations is based on continuous improvement from the 5 year
20 average of 1.4 per cent. In contrast, the CEA benchmarks are over 2.5 per cent.

21

22 **4.2 OM&A Unit Energy Cost**

23 Hydroelectric benchmarks OM&A cost performance of its stations by participating in the
24 Hydroelectric Generation Benchmarking Program that is carried out by Navigant
25 Consulting. The Navigant benchmarking program includes a best practices and data
26 review workshop held annually with participants. Hydroelectric also participates in the
27 EUCG annual OM&A benchmarking program. As mentioned earlier, Hydroelectric has
28 applied many best practices in the past ten years which have resulted in significant
29 savings that are already embedded into business plans/budgets.

1 The Navigant Consulting benchmarking participants are predominantly from Canada
2 (i.e., BC Hydro, Hydro-Quebec, Nova Scotia Power, Great Lakes Power, TransAlta
3 Utilities, Newfoundland and Labrador Hydro) and the United States (i.e., Tennessee
4 Valley Authority, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, Southern
5 California Edison, Chelan County PUD). The hydroelectric stations in this group of
6 utilities are diverse in size, type, location and age, and include a mix of run-of-the-river,
7 peaking, and pumped storage stations.

8
9 Costs included in the Navigant Consulting benchmarking are operations, plant
10 maintenance, waterways and dam and other maintenance, support (i.e., engineering,
11 finance, corporate support) and public affairs and regulatory. Public affairs and
12 regulatory costs include items such as water rentals and usage fees, gross revenue
13 charge, major environmental costs such as fish/wildlife operations and studies, as well
14 as special licensing fees (e.g., FERC re-licensing in the U.S.).

15
16 The study results are generally segmented into various peer groupings. Cost drivers
17 used to determine peer groupings include unit/station sizes, number of units, and age.

18
19 The cost benchmarking data presented is for OM&A costs only (referred to as “Partial
20 Function Costs” in the Navigant Program). Navigant Consulting also performs a Total
21 Cost Analysis which includes public affairs and regulatory costs. These public affairs and
22 regulatory costs, including Ontario’s Gross Revenue Charge, are externally mandated
23 and not within the control of a utility. Therefore, they are not relevant when assessing
24 and benchmarking operations, maintenance and administration costs (which are
25 generally within management control)¹.

26
27 The results of the Navigant Consulting and EUCG OM&A unit energy cost benchmarking
28 programs are summarized below in Charts 4 and 5 respectively. The cost benchmarking
29 results from 2006 - 2008 show that, collectively, the regulated facilities were in the top
30 quartile.

¹ OPG excludes these costs from its Performance Targets, as indicated in Section 3.0.

1 The OM&A unit energy cost benchmarking demonstrates that OPG's regulated
 2 hydroelectric facilities are cost competitive, in addition to having very good reliability,
 3 safety and environmental performance. OM&A costs for the regulated hydroelectric
 4 facilities are a function of their age, condition and specific circumstance relative to their
 5 peer group. Reliable operation is achieved by effective maintenance, but this tends to
 6 place upward pressure on OM&A cost.

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Chart 4
Navigant Consulting Hydroelectric Benchmarking Results

| Measure | Name of Station/Grouping | 2006 | 2007 | 2008 | Comparison Details/Note for 2008 | Source and Peer Group |
|--|---|-----------|-----------|-----------|----------------------------------|--|
| OM&A Unit Energy Cost (USD/MWh) (OM&A defined by HJA) | DeCew Falls I | 47.7 (Q4) | 40.6 (Q4) | 40.6 (Q4) | Q4 from 30.6 to 81.2 | Haddon Jackson Associates (HJA): 25 micro plants (< 30 MW) |
| | DeCew Falls II | 7.7 (Q3) | 8.5 (Q4) | 5.4 (Q3) | Q3 from 5.0 to 8.0 | HJA: 42 medium plants (150 to 400 MW) |
| | SAB I | 5.3 (Q4) | 6.9 (Q4) | 8.2 (Q4) | Q4 from 5.7 to 8.2 | HJA: 13 med-large plants (400 to 700 MW) |
| | SAB II | 1.6 (Q1) | 1.5 (Q1) | 1.4 (Q1) | Q1 from 0.6 to 1.9 | HJA: 25 large plants (700 MW or more) |
| | SAB PGS | 47.1 (Q4) | 61.7 (Q4) | 81.2 (Q4) | Q4 from 22.8 to 81.1 | HJA: 15 PGS plants |
| | Saunders | 2.1 (Q3) | 2.4 (Q3) | 2.5 (Q3) | Q3 from 2.2 to 3.6 | HJA: 25 large plants (700 MW or more) |
| | 5 OPG plants as above (Beck PGS excl'd) | 2.6 (Q1) | 2.8 (Q1) | 3.3 (Q1) | Q1 from 0.6 to 3.8 | HJA: 166 plants |
| | All 6 OPG plants (including Beck PGS) | 2.9 (Q1) | 3.2 (Q1) | 3.3 (Q1) | Q1 from 0.6 to 4.0 | HJA: 190 plants |

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Note:
 The above unit energy costs are in U.S. dollars and include both hydroelectric common cost allocations and corporate cost allocations. Currency conversion is based on the official Bank of Canada average midpoint Canadian to U.S. exchange rates (2003 = .7135; 2004=.7683; 2005=.8253, 2006 = 0.8829, 2007 = 0.91934, 2008 = .9736)

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Chart 5
EUCG Hydroelectric Benchmarking Results

| 2007-2008 Unit OM&A Cost Ranking - 241 (2008) plants including OPG plants. | | | | |
|---|-----------------------------------|-----------------------------------|---|--------------------------------------|
| Station | 2007 OM&A USD/ MWh | 2008 OM&A USD/ MWh | Comparison Details Note for 2008 | 2008 Rank/ Peer Group Count |
| DeCew Falls II | 8.0 (Q2) | 5.6 (Q1) | Q1 from 3.2 to 7.1 USD/ MWh | # 10 out of 84 plants (100-500 MW) |
| SAB I | 7.9 (Q2) | 10.6 (Q2) | Q2 from 7.1 to 11.1 USD/ MWh | # 40 out of 84 plants (100-500 MW) |
| SAB II | 1.8 (Q1) | 2.0 (Q1/2) | Q1 from 1.0 to 2.0 USD/ MWh | # 5 out of 19 plants (500+ MW) |
| SAB PGS | 55.2 (Q3/4) | 86.0 (Q4) | Q4 from 48.8 to 86.0 USD/ MWh | # 6 out of 6 plants (P-G) |
| Saunders | 2.1 (Q2) | 2.8 (Q2) | Q2 from 2.0 to 7.2 USD/ MWh | # 7 out of 19 plants (500+ MW) |
| All 5 OPG plants | 3.0 (Q1) | 3.7 (Q1) | Q1 from 1.0 to 8.7 USD/ MWh | #5, 7, 25, 76, 211 out of 241 plants |

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Notes:

- 2008 Unit Production Costs for 241 plants including 30 OPG plants (5 regulated and 25 unregulated).
- DeCew Falls 1 is not included in EUCG Cost Benchmarking Program because EUCG does not benchmark units less than 10 MW)

The OM&A unit energy cost ranking for the regulated hydroelectric facilities is negatively impacted by the significant OM&A expenditures at the Sir Adam Beck stations and R.H. Saunders required to maintain and operate the Joint Works with NYPA (e.g., ice booms and ice breaking operations, International Control Dam, Iroquois Control Dam). These additional structures and activities are not typical of most of the generating stations that are benchmarked, and account for approximately \$5M to \$7M per year in OM&A costs (or 7 to 12 per cent of total annual OM&A costs for the regulated hydroelectric facilities). In 2010 and 2011, NYPA has increased OM&A project requirements by \$2.4M and \$1M respectively compared to the amounts that OPG projected in its 2009 - 2013 business plan.

Explanations of each generating station's ranking and its specific cost issues are provided below:

21
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1 4.2.1 R.H. Saunders

2 In addition to the special Joint Works costs identified above, the relative OM&A costs at
3 R.H. Saunders is higher than other plants in its peer group due to the following
4 characteristics of the facility:

5 • There is a need for extensive instrumentation and ongoing monitoring of concrete
6 “growth” associated with alkali-aggregate reaction at the station. Alkali-aggregate
7 reaction is a chemical reaction within the concrete structure (between the cement
8 and certain types of aggregate) resulting in concrete “growth”. In the mid to late
9 1980’s this growth led to major operational and structural problems. A major
10 rehabilitation program was implemented in the 1990’s to mitigate the effects of the
11 concrete growth and restore operational reliability. The program included cutting
12 “slots” between each of the 16 units using a special diamond wire technique,
13 repairing the powerhouse structure, and replacing major mechanical and electrical
14 equipment. It is difficult to estimate when the concrete growth will stop, thus the
15 growth and the re-established joints between the units are being monitored. If it is
16 determined in the future that the joints are “closing up” leading to operational
17 problems, re-slotting of the units will be required. Based on monitoring to date, re-
18 slotting will likely be required in the next four to seven years.

19

20 • R.H. Saunders has on-site operators for both operations and site security. Because
21 R.H. Saunders is situated on the St. Lawrence River, which is transected by the
22 international border with the United States, site presence is necessary to ensure
23 security and public safety. The St. Lawrence - Franklin D. Roosevelt plant on the
24 U.S. side (owned by NYPA) is connected to the R.H. Saunders plant. Local presence
25 is also required to carry out our operational and maintenance commitments with
26 respect to the Joint Works (including water control at the Iroquois Control Dam and
27 annual installation and removal of ice booms), emergency preparedness, segregated
28 mode of operation switching operations, and water transactions. Absent these
29 unique circumstances, R.H. Saunders could be operated remotely from the control
30 centre at Chenaux Generating Station (approximately 200 km away).

31

1 The above two major issues will likely not improve or change in the future, thus the R.H.
2 Saunders OM&A ranking is expected to remain stable for the 2010 - 2012 period.

3
4 4.2.2 Sir Adam Beck I

5 The OM&A costs of Sir Adam Beck I are generally higher than median compared to its
6 peer groups in both benchmarking studies (i.e., second quartile in EUCG and fourth
7 quartile in Navigant) due to the following factors:

- 8 • The station is over 85 years old and the “power train” equipment has reached end of
9 life and needs rehabilitation or replacement (condition varies with each unit).
- 10 • Until 2009, three of the ten units were 25 Hz units. The last two in-service 25 Hz
11 units and the frequency converter were taken out-of-service at the end of April 2009.
12 The Unit G7 conversion from 25 to 60 Hz and upgrade was completed within budget
13 and schedule in 2009. The 25 Hz units generally required more maintenance than
14 most 60 Hz units due to their very poor condition. Also, there were additional costs to
15 maintain the additional frequency changer equipment which converted energy from
16 25 to 60 Hz and vice-versa, and the Niagara Transformer Station which was
17 specifically required for the 25 Hz system.

18
19 The unit rehabilitation/upgrades, the removal of two 25 Hz units from service, and the
20 shutdown of the Niagara Transformer Station and the frequency changer, are expected
21 to gradually reduce OM&A costs at Sir Adam Beck I over the next five years. As such,
22 the station’s benchmarking performance is expected to improve after all the work is
23 completed.

24
25 4.2.3 Sir Adam Beck II

26 Sir Adam Beck II is expected to remain in the top quartile of its peer group for the OM&A
27 unit energy cost benchmark in the next five years. The 2008 Navigant benchmarking
28 results also identified Sir Adam Beck II as a leading performer in maintenance costs per
29 MWh versus service level (as measured by availability and EFOR) category. All 16 units
30 at the station were upgraded with new more efficient equipment installed from 1996 -

1 2005. Thus, the excellent cost and reliability performance is expected to continue in
2 2010 - 2012.

3

4 4.2.4 Sir Adam Beck Pump Generating Station ("PGS")

5 Sir Adam Beck PGS costs are in the fourth quartile primarily due to the age and unique
6 operation of the station relative to all other pumped storage stations. This plant is
7 benchmarked with other pumped storage stations that are much more modern and less
8 complex in design, have much larger units (i.e., economies of scale), and which operate
9 differently than Sir Adam Beck PGS. In addition to its role in pumping water for use
10 during peak periods (which is typical for PGS's), Sir Adam Beck PGS is used to: 1)
11 control the cross-over elevation of the Sir Adam Beck canals, 2) assist in automatic
12 generation control, and 3) provide for flexibility and optimization of operations at the Sir
13 Adam Beck complex.

14

15 Due to this unique role, the units experience a high frequency of control actions leading
16 to more wear and tear, and resulting maintenance. For example, in 2009, the Sir Adam
17 Beck PGS was often fully dispatched to pump in order to mitigate surplus baseload
18 generation conditions in Ontario and prevent or reduce nuclear maneuvering. These
19 factors contribute to significantly higher OM&A unit energy costs compared to a
20 conventional hydroelectric station or a typical pump generating station, as well as
21 reduced availability and reliability.

22

23 4.2.5 DeCew Falls

24 The DeCew Falls I OM&A unit energy costs are in the third and fourth quartiles of the
25 Navigant benchmarking results due to the very old age (109 years) of the plant, the
26 condition of the plant and small unit sizes, which results in high maintenance costs per
27 unit of energy produced. The steel penstocks have reached end of life and are being
28 replaced. A detailed plant condition assessment and life cycle plan indicated
29 rehabilitation of the existing plant was the best alternative. A major overhaul of some of
30 the units is also planned to extend the life of the facility, which on completion can be
31 expected to stabilize on-going maintenance costs.

1 With regard to DeCew Falls II, OM&A costs increased in 2006 and 2007 due to the
2 major overhaul work performed on the units. This caused the ranking to decline from
3 third quartile in 2005/2006 to fourth quartile in 2007. The overhaul program for DeCew
4 Falls II was completed in mid-2007, thus major overhaul costs will no longer be incurred.
5 Both the Navigant and EUCG cost benchmarking indicate that the station's OM&A cost
6 performance has improved in 2008, compared to previous years.

7

8 **4.3 Safety (Accident Severity Rate)**

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

16

17 In 2008, OPG's regulated hydroelectric Accident Severity Rate was zero and OPG
18 ranked first out of the 5 CEA members with Hydro Businesses >200 employees.

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LIST OF ATTACHMENTS

Attachment 1: Regulated Hydroelectric 2010 - 2014 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.



Hydro Generation Business Plan 2010 to 2014

Presentation to OPG Board of Directors

November 19, 2009

John Murphy
EVP Hydro

Business Plan Outline

1. Setting the Context
 - The Assets
 - Age Profile & Re-Investment Frequencies
2. Major Initiatives
3. Performance and Cost Summary
4. Plan Over Plan Changes - OM&A & Capital
5. Hydroelectric Development Plan
6. Project Expenditures to Maintain and Improve Existing Assets
7. Project Expenditures – Safety and Environmental Programs
8. Runner Upgrade Program
9. Energy Production Plan
10. Reliability
11. Aboriginal Program
12. Demographics and Staffing Strategy/Plan
13. Benchmarking – OM&A Unit Energy Cost and Reliability
14. Key Business Risks

Appendix A – Additional Information

- Station Statistics
- Portfolio Classification and Project Prioritization System
- Capital Expenditures - History and Future
- Hydro Revenue, Cost, Staffing and Other Performance Information
- Year Over Year Changes
- Capacity Changes During Planning Period
- Energy Production Forecast – Impacts of Surplus Baseload Generation (Details)

Appendix B - Regulated Asset Information

Appendix C - Unregulated Asset Information

The Assets



RH Saunders GS

PEOPLE / WORK CENTRES / LAND

| | |
|---|--------------------------------|
| PLANT GROUPS | 5 |
| WORK CENTRES | 22 |
| CONTROL CENTRES (includes ICD) | 7 (was 18 pre-1999) |
| TOTAL STAFF | ~1060 |
| OPERATORS | ~100 (was 200 pre-1999) |
| NO. OF RIVER SYSTEMS | 24 |
| HYDRO OWNED LAND | ~17,000 hectares |
| LEASED LAND (flooded) | ~800, 000 hectares |

STATIONS PROFILE

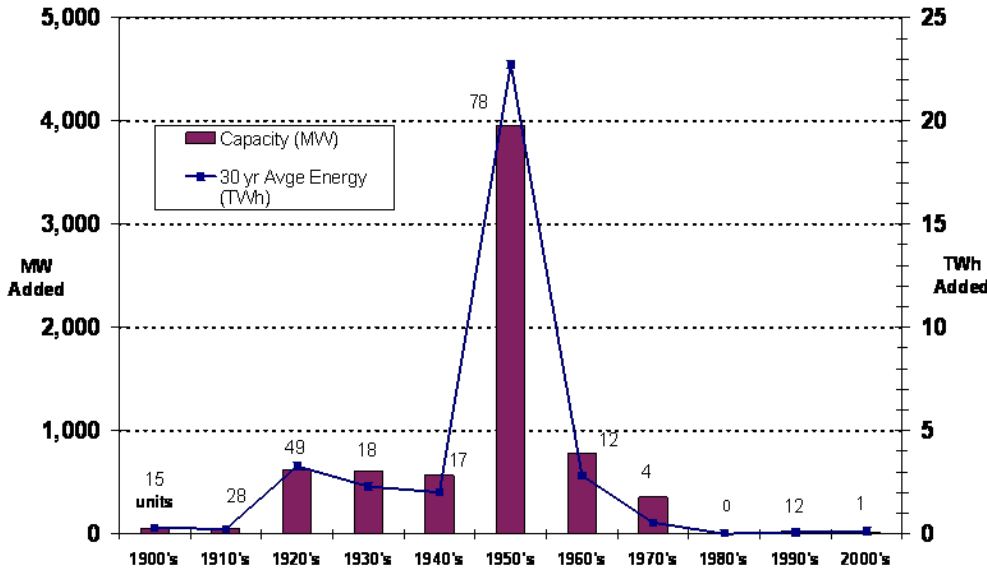
| | |
|------------------------------------|--|
| NO. OF STATIONS | 65 (4 stations being redeveloped) |
| AVERAGE ENERGY CAPACITY | 34.7 TWh 6943 MW |
| AVERAGE AGE | 70 yrs |
| NO. OF GENERATING UNITS | 230 |
| SMALLEST / LARGEST UNIT | 1 MW / 137 MW |
| NO. OF DAMS | 231 |
| BOOK VALUE | \$6.8 billion |



Ragged Rapids GS

The Assets: Age Profile & Re-Investment Frequencies

HYDRO AGE DISTRIBUTION OF CAPACITY AND ENERGY



| STATION COMPONENTS | OVERHAUL/REPLACEMENT FREQUENCY (YEARS) | | | | | | | | | | Range (M\$) |
|-----------------------------------|--|----|----|----|----|----|----|----|----|-----|-------------|
| | 10 | 20 | 30 | 40 | 50 | 60 | 70 | 80 | 90 | 100 | |
| GENERATORS | | | | | | | | | | | |
| rewind | | | | | | | | | | | 0.5 to 4 |
| TURBINES | | | | | | | | | | | |
| major overhaul (mechanical parts) | | | | | | | | | | | 1 to 3 |
| replace runners | | | | | | | | | | | 1 to 5 |
| PROTECTION & CONTROL | | | | | | | | | | | |
| replace | | | | | | | | | | | .5 to 5 |
| SERVICE WATER & AUXILIARIES | | | | | | | | | | | |
| replace | | | | | | | | | | | 0.4 to 10 |
| HEADGATES / SLUICE GATES | | | | | | | | | | | |
| reb uild/replace | | | | | | | | | | | 0.2 to 4 |
| PENSTOCKS | | | | | | | | | | | |
| reb uild woodstave | | | | | | | | | | | 7 to 15 |
| replace steel | | | | | | | | | | | 7 to 15 |
| CRANES | | | | | | | | | | | |
| reb uild/replace | | | | | | | | | | | 0.5 to 5 |
| CIVIL STRU CTURES (BUILDINGS) | | | | | | | | | | | |
| reb uild/replace | | | | | | | | | | | 0.2 to 100 |
| CIVIL STRU CTURES (DAMS) | | | | | | | | | | | |
| reb uild/replace | | | | | | | | | | | 1 to 100 |
| AQUADUCTS & TUNNELS | | | | | | | | | | | |
| reb uild/replace | | | | | | | | | | | 30 to 1,600 |

LEGEND
 Overhaul/Repair (Blue)
 Rebuild/Replace (Red)

- Average age of stations is 70 years.
- 70% of Hydro capacity built during the 1950's and 1960's.
- Equipment service lives range between 30 to 50 yrs.
- Structures such as dams, penstocks, powerhouses, canals, etc. typically require repairs every 25 to 50 years. Replacement of some civil components is required every 40 to 75 years (eg, wood stave penstocks, stop-logs, etc).
- There is risk of deteriorating performance and safety without significant continued re-investment (due to demographics of portfolio, and large number and variability of stations/units/equipment).
- Re-investment levels of about 1% to 3% per yr of "replacement cost" are considered reasonable by industry experts. Hydro has invested approximately 0.5% to 1.5% per yr of "replacement cost" in the past 10 years (excludes new facilities). Determination of appropriate investment levels should consider station/fleet age and condition, type of equipment, station role (peaking vs base), past investment strategy (eg, harvesting), reliability targets, etc.
- The Business Plan addresses the need to sustain and improve the existing assets for long term per the Hydro mandate. Plant Condition Assessment/Life Cycle Plans and Portfolio Approach to Asset Management used to determine and prioritize investments (Appendix A).

Major Initiatives

➤ Invest in New Hydroelectric Developments per Government Mandate

- ✓ Continue with construction of Niagara Tunnel, Upper Mattagami/Hound Chute and Healey Falls projects.
- ✓ Obtain approvals and start construction of Lower Mattagami project, [REDACTED]

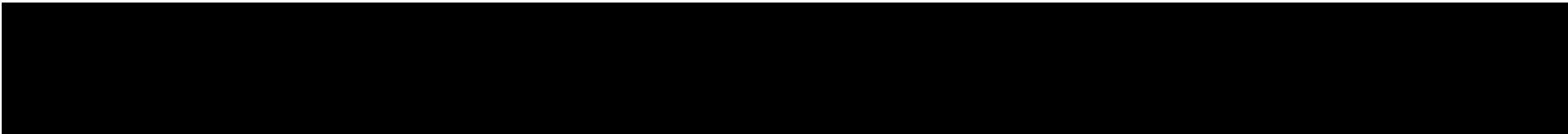
➤ Re-invest in existing assets to maintain/improve their condition, reliability and efficiency

- ✓ Availability will range from 91.0% to 92.8%.
- ✓ EFOR target is 1.5% (proposed stretch target is 1.4%).
- ✓ Continue replacement/refurbishment civil infrastructure including dams, penstocks, and building envelopes.
- ✓ Continue rehabilitations/upgrades at major stations.
- ✓ Continue runner upgrade program (additional 66 MW of capacity and 144 GWh from 2010 to 2014).
- ✓ Increase/advance reinvestment in small hydro plants (eg, replace aging penstocks, gates, etc) to ensure continued long term safety and performance.

➤ Improve Dam and Public Safety through investments and improved processes:

- ✓ Rehabilitate/upgrade/repair civil works and maintain/improve safety of dams to address deterioration and deficiencies in ageing structures and sluice gates.
- ✓ Improve public safety through the addition of safety booms, fencing, signs, cameras, special structures at certain sites, and enhancement/integration of existing procedures.
- ✓ Increase Dam Safety Surveillance as per the recommendations of Independent Dam Safety Panel.
- ✓ Continue to participate in, and influence, the development of provincial regulations with the MNR.
- ✓ Develop and implement Geographic Information System (GIS).

Major Initiatives (cont'd)

- Invest In People
Continue rejuvenation and training of Hydro workforce to address ageing demographics and new work associated with development projects and changing regulatory and internal governance requirements.
 - Improve Accident Severity Rate and All Injury Rate and maintain registration in OHSAS 18001.
 - Maintain/improve environmental performance in the area of spills risk management and containment testing, and maintain registration in ISO 14001
 - Strengthen relationships with First Nations and Metis
Build relationships, consult and partner with First Nations on new developments, and continue activities to support the Aboriginal Relations Policy
 - Maintain/improve relationships with provincial and federal government agencies and community stakeholders (to maintain our rights to the “fuel” on the watersheds).
 - Improve project planning and execution through enhancement of Project Management processes, systems, training and oversight.
- 

OM&A - Plan Over Plan

Major Changes

- Some lower risk OM&A projects have been deferred from 2010 to later in planning period. Consulting and discretionary costs have been reduced to meet Cost Reduction Challenge.
- Modest staff additions to address demographics, additional project and regulatory requirements in operations, and increased dam safety surveillance.
- Central Hydro Plant Group organization will be strengthened and improvements will be made to managed systems, public safety, and project and maintenance management.
- NEPG and NWPG support staff added to assist in construction and ultimate operation of the Upper and Lower Mattagami projects.
- Niagara Bridge Divestiture Strategy: OPG has legal obligations to maintain and replace certain bridges at the end of their life. OPG will pay municipalities to replace these bridges and turnover all responsibility to the municipalities. This will eliminate future cost and legal liabilities associated with these bridges.
- Increases in Geographic Data System data acquisition (flight surveys and LIDAR) and mapping system costs.
- Reductions due to IFRS accounting changes (transfer SAVH from OM&A to Capital).
- Labour and payroll burden rates have been reduced.

| <u>OM&A - Plan Over Plan</u> | <u>2009 Proj'n</u> | <u>2010</u> | <u>2011</u> | <u>2012</u> | <u>2013</u> |
|---|------------------------|-------------|-------------|-------------|-------------|
| Last Year's Approved Plan (\$M) | | | | | |
| Changes | | | | | |
| Corporate Reduction Challenge | | -5.0 | | | |
| Mechanical, Civil, Electrical Work Program (Reprioritization & Scope Change) | 1.2 | -2.7 | -5.6 | -1.0 | -1.5 |
| Additional New Hires, Apprentices and Operators - Demographics | | 0.8 | 0.4 | 0.5 | 0.3 |
| Plant Group Operations Support for Upper Mattagami, Lower Mattagami, Healey Falls and Little Jackfish | | | | | |
| New Hydro Development Project Increases (includes Pumped Storage) | | | | | |
| Niagara Bridge Replacement/Divestiture Program | 4.0 | 1.8 | 6.9 | 0.0 | 0.0 |
| Public Safety Increases (Signs, Fencing, Booms, etc) | | 1.5 | 0.6 | 0.6 | 0.6 |
| Dam Safety Surveillance Inspection Increases (per Independent Panel) | | 1.0 | 1.0 | 1.0 | 1.0 |
| Central Hydro PG (Strengthen Organization/Due Diligence & Improve Maintenance) | 0.2 | 1.4 | 1.6 | 1.8 | 1.9 |
| Re-investment in the Small Hydro Fleet (Project Changes) | | | | | |
| Niagara Joint Works Changes (NYPA cost increases) | | 1.2 | 0.5 | | |
| Geographic Information System (GIS) Implementation | | 1.8 | 0.2 | 0.2 | 0.2 |
| Shoreline Remediation/Erosion Protection Projects (First Nations) | -2.9 | 0.7 | | | |
| Miscellaneous Changes | -5.1 | 0.6 | 3.7 | 1.4 | -0.5 |
| OM&A Submission (before labour rate & payroll burden reduction) | | | | | |
| SAVH Transferred to Capital | | -1.7 | -1.7 | -1.7 | -1.7 |
| Labour Rate & Burden Reduction | | -9.1 | -9.7 | -11.6 | -11.4 |
| OM&A Submission | | | | | |
| Change in OM&A From Last Year's Plan | | | | | |

Capital - Plan Over Plan

Major Changes

- Project costs on both the operations side of business and new developments have been increased to reflect actual contract bids, and latest material/equipment/contracting cost information.
- Replacement of old wood stave and steel penstocks at small hydro plants (eg, South Falls, Matabitchuan) have been advanced. DeCew Falls 1 steel penstock to be replaced in 2009 to 2011.
- Niagara Tunnel in-service date and cost has been changed to December 2013 and \$1.6 billion, respectively. Cash flows and energy production assumptions for the tunnel are aligned with this in-service date.
- Pre-concept phase costs for new development projects and initiatives such as pumped storage added.
- Lower Mattagami total cost increased to [REDACTED] and schedule per latest contractor estimates.

| <u>Capital - Plan Over Plan</u> | <u>2009 Proj'n</u> | <u>2010</u> | <u>2011</u> | <u>2012</u> | <u>2013</u> |
|--|--------------------|-------------|-------------|-------------|-------------|
| Last Year's Plan (\$M) | | | | | |
| Operations Changes | | | | | |
| SAB1 G10,3,5,4 Upgrade changes (Runner Upgrade/Rewind) | -2 | -10 | -10 | -5 | -3 |
| Civil Project Changes | 2 | 6 | 9 | 0 | -3 |
| Major Mechanical, Electrical & P&C Equipment Replacements (Reprioritization & Scope Changes) | -5 | 3 | 4 | 2 | 5 |
| Equipment Cost Increases | 2 | 4 | 0 | 0 | 0 |
| Operations Projects deferred to align with Hydro Development projects | | | | | |
| Penstock Replacement Changes and Cost Increases | 1 | -2 | 15 | 4 | 0 |
| Small Hydro Re-Investment | | | | | |
| New Development Changes | | | | | |
| Niagara Tunnel Project | 49 | 7 | 145 | 197 | 214 |
| Lower Mattagami | | | | | |
| Upper Mattagami and Hound Chute | | | | | |
| Mattagami Lake Dam | | | | | |
| Healey Falls | | | | | |
| Little Jackfish | | | | | |
| Hydro Development Project and Other Changes (Timing) | | | | | |
| Capital Submission | | | | | |
| Change in Capital From Last Year's Plan | | | | | |

Hydroelectric Development Plan

| | Capacity | Pre-2009 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Bal | Total |
|--|----------|----------|-------|-------|-------|-------|-------|------|-----|-------|
| | MW | | \$M | \$M | \$M | \$M | \$M | \$M | \$M | \$M |
| Projects In-Progress | | | | | | | | | | |
| Niagara Tunnel Project (from NTP Info Sheet) | | 434.5 | 222.7 | 241.8 | 288.0 | 199.0 | 214.0 | 0.0 | 0.0 | 1,600 |
| Upper Mattagami & Hound Chute | | | | | | | | | | |
| Healey Falls | | | | | | | | | | |
| Subtotal (Projects In-Progress) | | | | | | | | | | |
| Projects In Definition Phase | | | | | | | | | | |
| Lower Mattagami | | | | | | | | | | |
| Mattagami Lake Dam | | | | | | | | | | |
| Little Jackfish | | | | | | | | | | |
| Subtotal (Definition Phase) | | | | | | | | | | |
| Projects in Concept/Pre-Concept (Corporate Provision) | | | | | | | | | | |
| Ranney Falls | | | | | | | | | | |
| Newpost Creek | | | | | | | | | | |
| Long Lake Dam | | | | | | | | | | |
| South Falls | | | | | | | | | | |
| OPG Control Dams | | | | | | | | | | |
| Lake Gibson | | | | | | | | | | |
| Moose River Basin (Greenfield) | | | | | | | | | | |
| Albany River (Hat & Chard) | | | | | | | | | | |
| Northern Rivers | | | | | | | | | | |
| Calabogie | | | | | | | | | | |
| Mavnard Falls | | | | | | | | | | |
| Concept/Pre-Concept - Corp. Provision | | | | | | | | | | |
| Total (Projects In-Progress, In Definition Phase & Pre-Def'n Phase) | | | | | | | | | | |

General

- Costs for projects presently in execution and definition phases are included in this business plan.
- Timing of execution phase for projects presently in definition phase will be dependent on government directives, HESA's (from OPA), agreements with First Nations, EA approvals, etc (timing of phases for each project shown on next page).

Pumped Storage

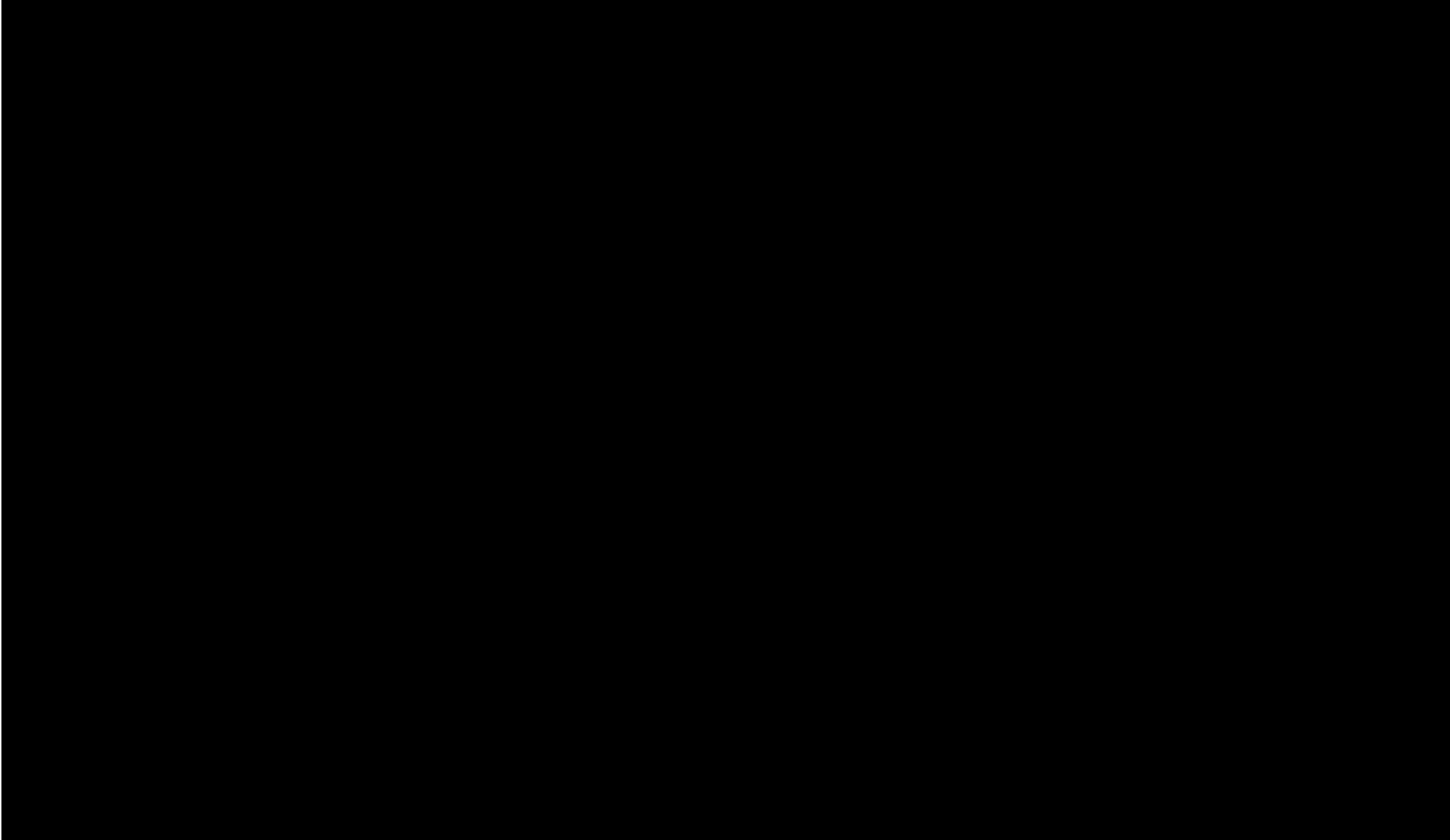
- Extensive review of historical information and international pumped storage installations completed and [redacted] OPG sites [redacted] [redacted] have been identified as being the most desirable for addition of pumped storage. As well, preliminary review of expansion of the existing Sir Adam Beck PGS reservoir has been conducted.

➤ [redacted]

Project In-Service Dates

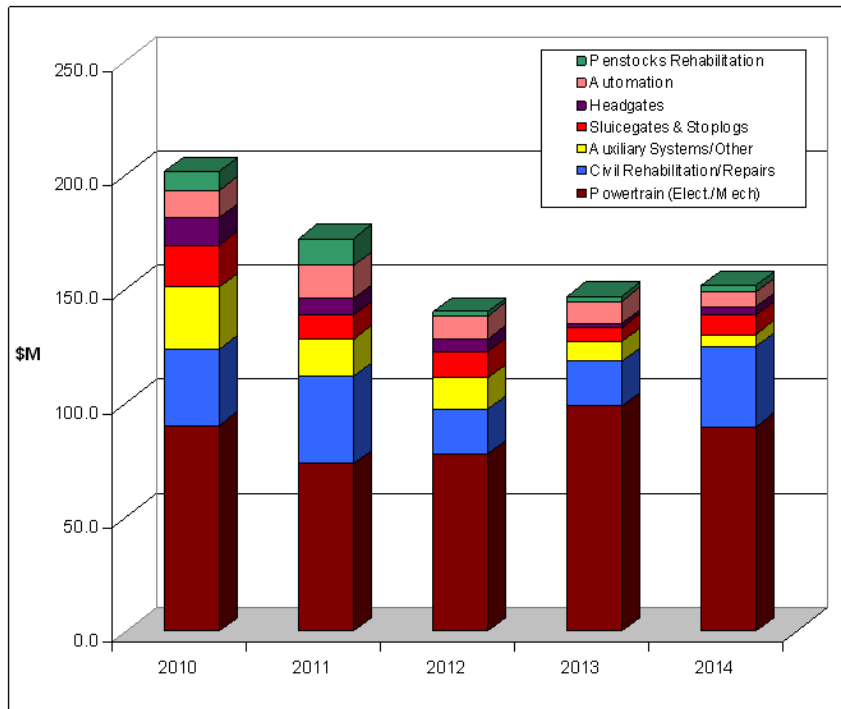
- Healey Falls: [redacted]
- Upper Mattagami/Hound Chute: [redacted]
- Niagara Tunnel: December 2013
- Mattagami Lake [redacted]
- Lower Mattagami: [redacted]

Hydroelectric Development Plan (Project Phases/Timelines)

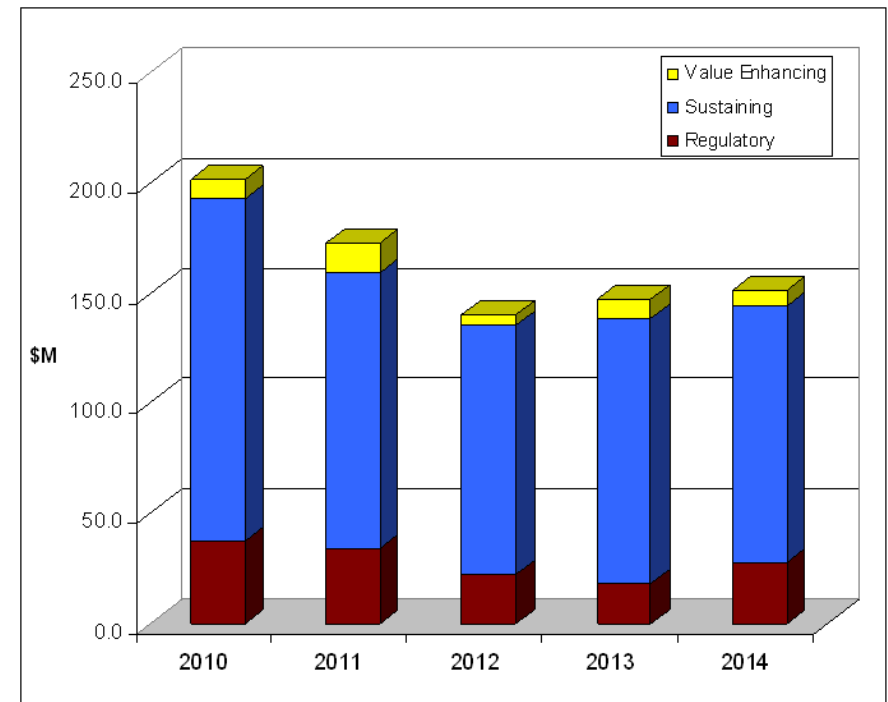


Project Expenditures To Maintain and Improve Existing Assets

By Discipline/Component



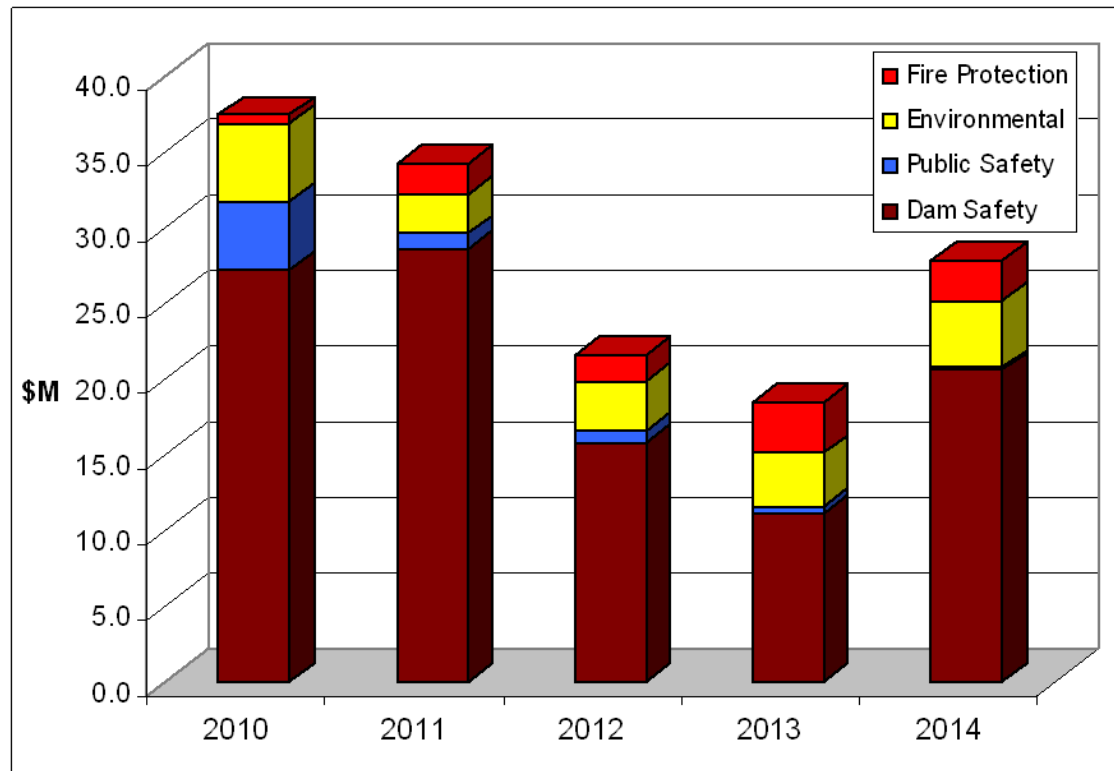
By Regulatory/Sustaining/Value Enhancing



Continued re-investment, averaging ██████████ per year in Capital and OM&A project expenditures, will be required to sustain and improve the existing assets per our mandate. Major investments will include:

- replacement of ageing “power train components” such as turbines, generators, transformers
- replacement of control equipment (automation) to improve efficiency and accommodate market dispatch requirements
- repairs, rehabilitation or replacement of ageing civil structures including powerhouses, penstocks, dams, sluiceways and bridges
- replacement and refurbishment of headgates and sluiceways
- runner upgrades/replacements
- investment in small hydro facilities

Project Expenditures - Safety and Environmental Programs

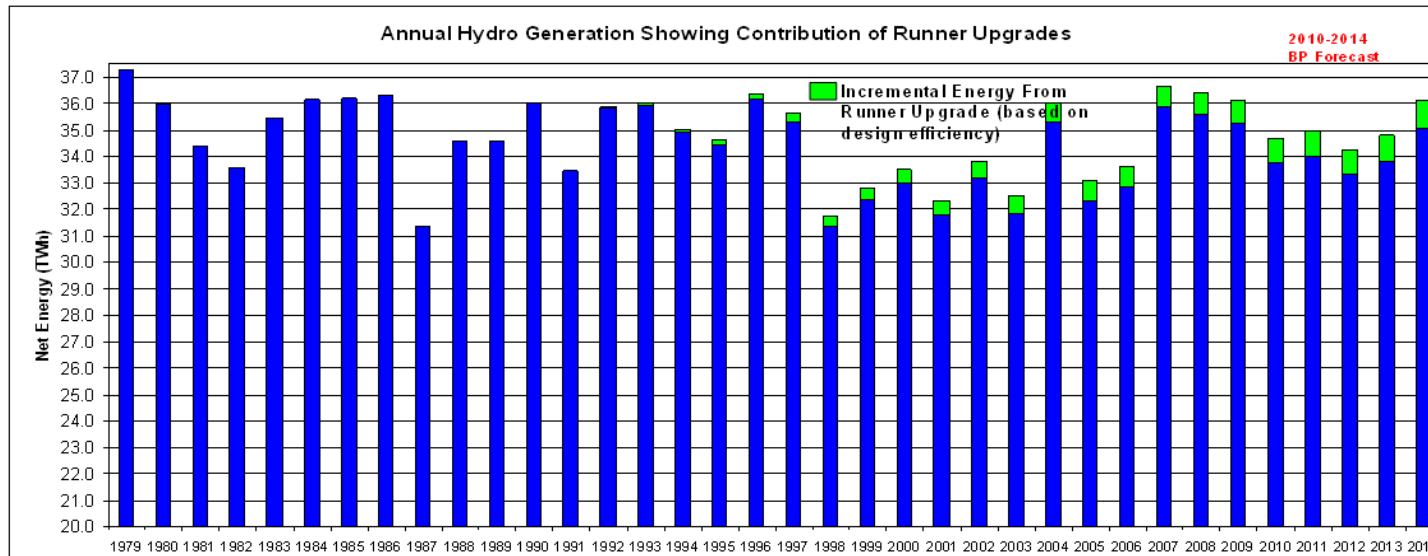
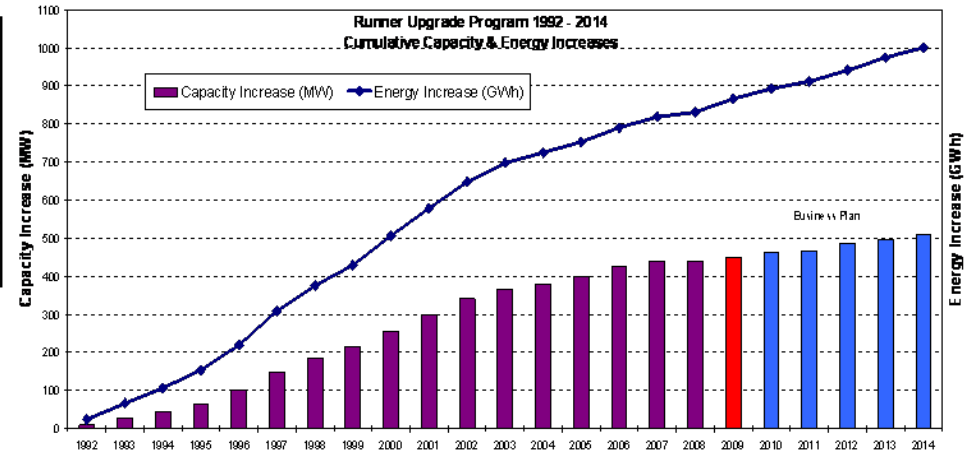


Project expenditures for safety and environmental programs during planning period:

- Public Safety (safety booms, fencing, signs, video cameras, special structures, etc) (5% of total safety and environmental project costs).
- Dam Safety (sluiceway & headgate refurbishments/additions, dam upgrades/ restoration)(74%).
- Environment (oil containment, turbine pit/sump improvements, underground piping remediation) (14%).
- Fire Protection (life safety projects). Program to be completed during planning period. (7%).

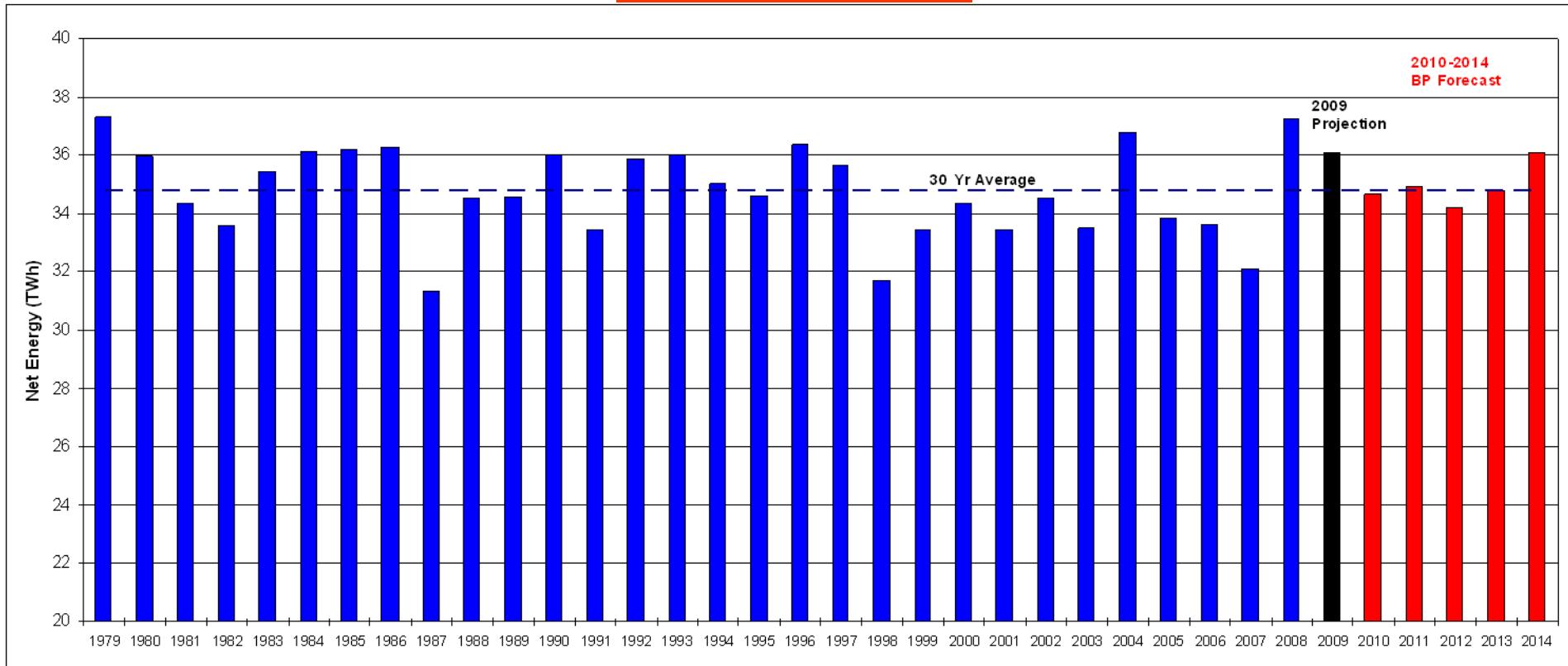
Runner Upgrade Program

| | Completed 1992 to 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total (2010 to 2014) |
|---------------------------------|---------------------------|------|------|------|------|------|------|-------------------------|
| CAPACITY (MW) | 439 | 11 | 13 | 4 | 19 | 18 | 12 | 66 |
| ENERGY (GWh) | 831 | 35 | 26 | 25 | 29 | 38 | 27 | 144 |
| TOTAL CAPITAL COST (M\$) | 167 | 15 | 9 | 14 | 8 | 12 | 7 | 51 |

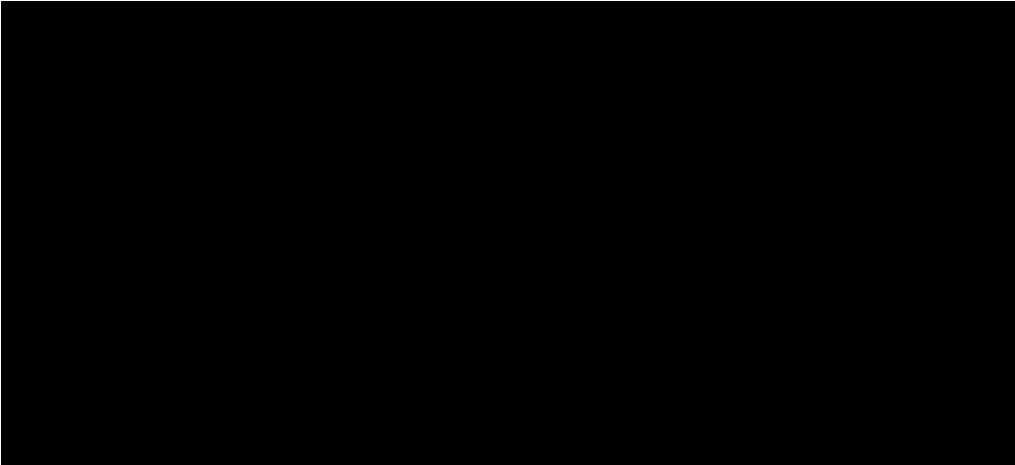


- In 2009, Hydro is adding 11.2 MW of capacity & 35.3 GWh of energy. During the planning period runner upgrades will add 65.9 MW and 144 GWh.
- Execution of remaining program will continue as quickly as practical. A business case will be developed for each project before proceeding (LUEC's presently estimated to be between 3 and 10 cents/kWh depending on project).
- The speed of execution may be impacted by IESO constraints, consideration of outage spill losses, coordination with other major work, resource availability (internal resources and external contractors) & coordination with development projects (at existing sites - LMD).

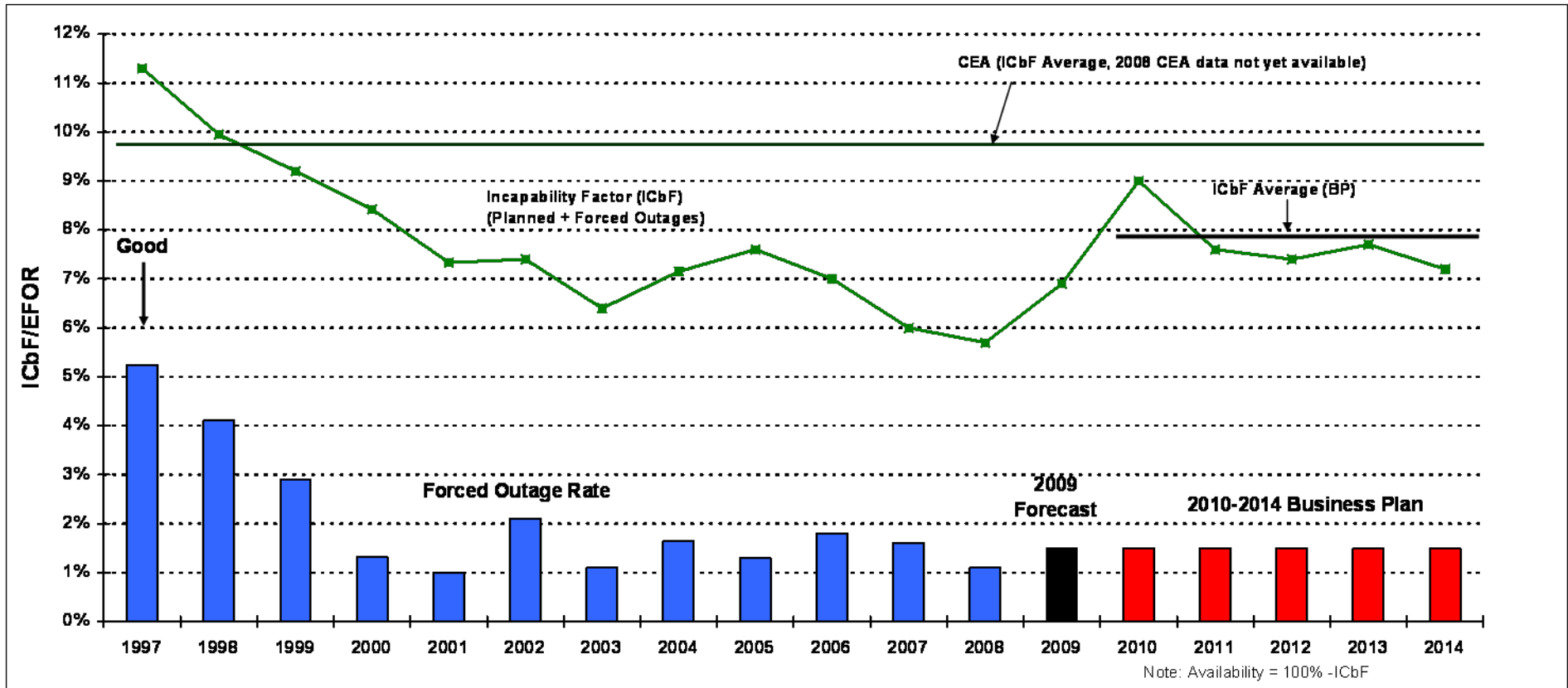
Energy Production Plan



- Base 2010 to 2014 energy forecast assumes median water levels and Surplus Baseload Generation (SBG) spill losses included per Energy Markets forecast (see graph)
- Major energy increases during business plan period include:
 - 2013: Niagara Tunnel Energy (1.6 TWh in 2014)
 - 2010: Upper Mattagami [REDACTED]
 - 2013/2014: Lower Mattagami [REDACTED]



Reliability



- Availability will average 92.2% (ICbF=7.8%) during the business planning period. This is significantly better than the CEA average.
- In 2010 to 2014, availability will be lower than the 2009 projection due to additional/long outages required for major rehabilitations and upgrades at several stations (eg, Sir Adam Beck 1 Units 9,10, 3, 4 & 5, Mountain Chute Unit 2, Des Joachims, Otter Rapids, Lower Notch, Little Long, Harmon, Abitibi Canyon (full station outage), Otto Holden, Pine Portage, Whitedog Falls, Alexander Falls).
- EFOR is assumed to average 1.5% during the business planning period. This is also significantly better than the CEA average. A stretch target of 1.4% is proposed for EFOR.
- EFOR & Availability may be negatively impacted by additional dispatches and stops/starts associated with SBG situation.

Aboriginal Program

| | 2009 Actual | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|----------------|------------|------------|------------|------------|------------|
| Community Relations and Outreach (M\$) Community Support | 1.0 | 1.1 | 1.1 | 0.6 | 0.6 | 0.6 |
| Capacity Building Support (M\$) Educational Partnership Scholarships/Bursaries Mentoring Project Participation | 1.6 | 4.3 | 4.1 | 3.6 | 3.6 | 3.6 |
| Employment Opportunities (M\$) New hires - regular/PT/Students | 0.8 | 1.3 | 0.6 | 0.5 | 0.5 | 0.5 |
| Contracting Opportunities (M\$) Contracts | 0.3 | 0.8 | 0.1 | 0.0 | 0.0 | 0.0 |
| Other Initiatives (M\$) | 0.0 | 0.7 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 3.8 | 8.3 | 5.9 | 4.7 | 4.7 | 4.7 |

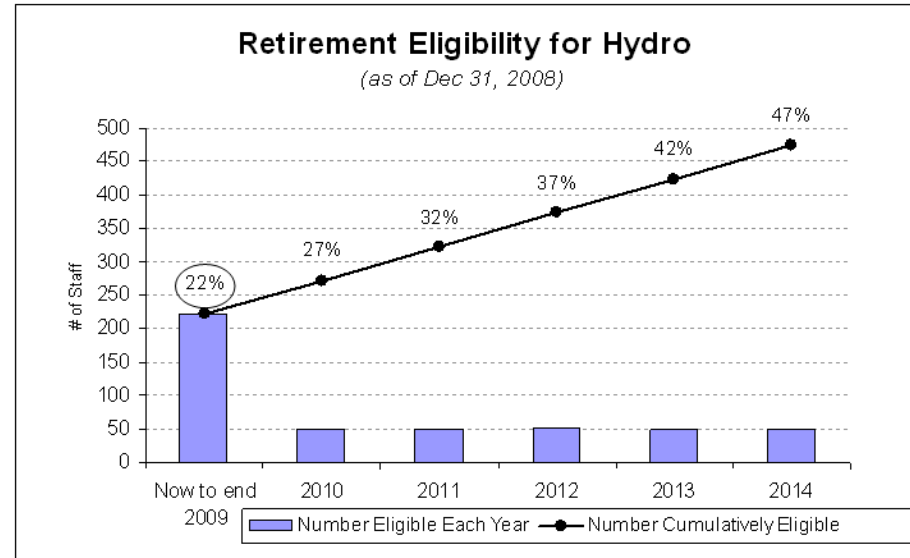
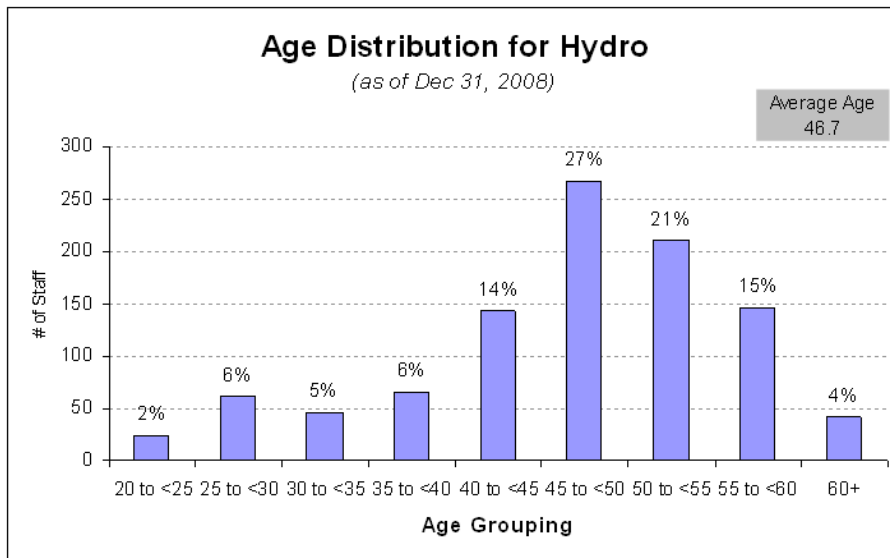
- Program includes both operations and hydroelectric development initiatives.
- Program covers 30 First Nations and Metis.
- Hydroelectric Development costs include support to First Nations for:
 - Commercial agreements
 - Technical studies/assistance
 - EA consultants
 - Employment training

Notes

1. Above costs are already included in Business Plan, either in base OM&A for the Plant Groups or Hydroelectric Development project costs.
2. Above table does not include past grievance settlement costs and remediation work (eg, Long Lac #58 shoreline remediation and Whitesand erosion repairs).
3. Above table does not include Plant Group and Aboriginal Affairs Division staffing costs to manage and carry out the aboriginal program.

Demographics

- During 2008 and 2009, significant progress has been made to reduce this risk through external hiring strategy (apprentices, Hydroelectric Operating Trades Trainee's, and Engineering/Professional Trainees).
- Demographics have marginally improved since 2008, but 22% of staff are still eligible to retire by end of 2009 and 47% by end of 2014. Thus, it is important to continue hiring and training strategy which was initiated in 2008 (see next page).

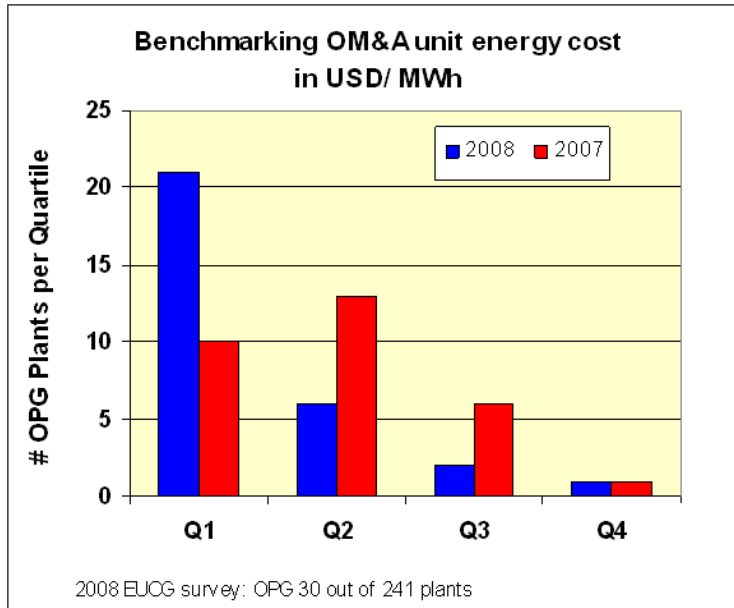


Staffing Strategy/Plan

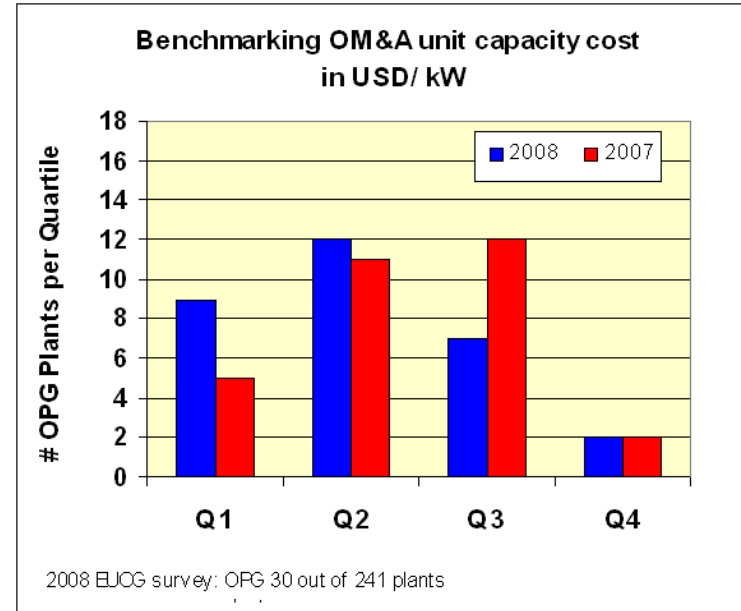
- Aggressive hiring strategy to attract skilled (“journey person”) trades external to the company.
- Apprenticeship Program – hiring and training apprentices to replace retiring skilled trades.
- “Strategic Complement” – Strategy of “over hiring” to account for unexpected attrition, high turnover, and long lead times required to hire staff.
- Succession Management – succession planning for leadership roles down to FLM level is formally underway.
- Knowledge Transfer – overlap new hires with anticipated retirements to ensure knowledge transfer.
- Re-establish Graduate Engineering Trainee Programs.
- Leadership/Supervisory Development Program.
- Reduce temporary staff, contract staff and consultants as regular staff complement increases.

| Regular Staff - Plan Over Plan | 2009 Proj'n | 2010 | 2011 | 2012 | 2013 |
|---|--------------------|-------------|-------------|-------------|-------------|
| Last Year's Plan (Staff) | | | | | |
| Changes | | | | | |
| Maintenance Staff Changes including Apprentices (Journey person Mechanical/Electrical Maintainers) | | | | | |
| Operations & Maintenance Support (engineering, project management, environment, public safety, regulatory support, public affairs, etc) | | | | | |
| Hydroelectric Development Staff Increases for Concept Phase Work and Project/Construction Management | | | | | |
| Plant Group Operations Support for New Development Projects (Upper Mattagami, Lower Mattagami, Little Jackfish) | | | | | |
| Central Hydro Plant Group (Organizational Reinforcement) | | | | | |
| Hydro Staff BP Submission | | | | | |
| Change in Total Staff From Last Year's Plan | | | | | |

Benchmarking of OM&A Costs – EUCG (2008)



| | 2008 OPG Plant Distribution | | | | total |
|----------|-----------------------------|------------|-------------|--------------|-------|
| | Q1 | Q2 | Q3 | Q4 | |
| USD/ MWh | 1.0 - 8.7 | 8.7 - 17.6 | 17.6 - 44.0 | 44.0 - 1,132 | |
| # plants | 21 | 6 | 2 | 1 | 30 |
| TWh | 33.1 | 3.8 | 0.3 | 0.1 | 37.3 |
| % TWh | 89% | 10% | 0.9% | 0.4% | 100% |

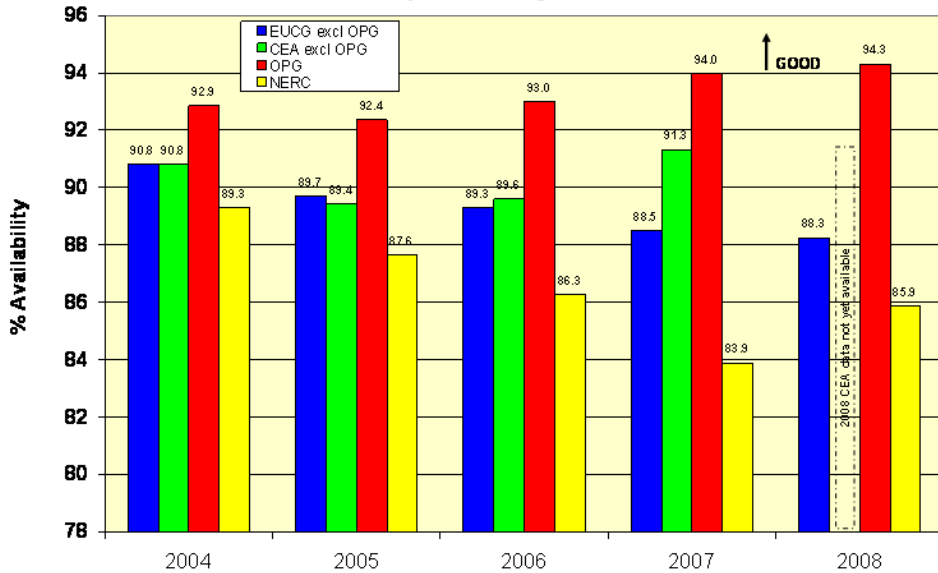


| | 2008 OPG Plant Distribution | | | | total |
|----------|-----------------------------|-------------|-------------|--------------|-------|
| | Q1 | Q2 | Q3 | Q4 | |
| USD/ kW | 7.2 - 24.0 | 24.0 - 44.3 | 44.3 - 96.4 | 96.4 - 1,860 | |
| # plants | 9 | 12 | 7 | 2 | 30 |
| MW | 4,206 | 2,038 | 650 | 42 | 6,935 |
| % MW | 61% | 29% | 9% | 0.6% | 100% |

- OM&A costs continue to be competitive with other EUCG participating utilities (99% of Hydro generation is in top two quartiles).
- Most of our large stations (eg, Saunders, Sir Adam Beck 2 and Des Joachims) are in the top quartile.

Benchmarking of Reliability (2004 – 2008)

Availability Factor Trend
 Hydro Generating Units

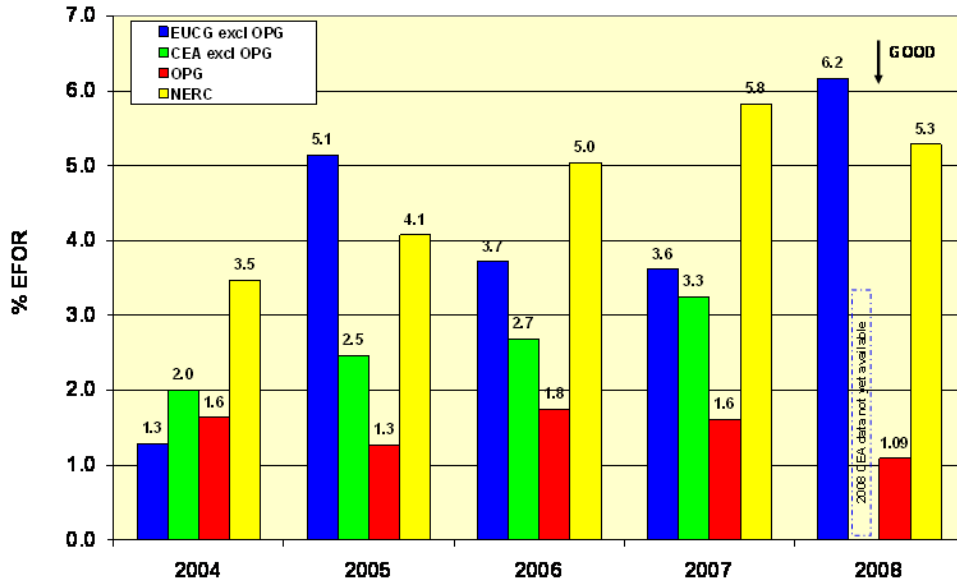


➤ Hydro Availability and EFOR continues to benchmark better than EUCG and NERC participants.

➤ Availability (EUCG Benchmarking)

- 10 Hydro plants are in the top quartile.
- 19 plants are better than the median. This accounts for 71% of Hydro capacity.

Forced Outage Rate Trend
 Hydro Generating Units



➤ Forced Outage Rate (EUCG Benchmarking)

- Hydro has 18 plants that are better than the median. This accounts for 52% of Hydro capacity.

Notes:

- 1) 30 OPG Hydro stations are included in the benchmarking. Benchmarking studies do not include small stations/units
- 2) CEA benchmarking data for 2008 is not yet available.

Key Business Risks

- Niagara Tunnel Project – Delays in schedule, increase in project cost and geological risk.
- Hydroelectric development project risks associated with project management capability, availability of qualified contractors and skilled labour, cost escalation, EA approvals, First Nations support/partnerships, obtaining PPA's or HESA's from OPA.
- Cost escalation risk - Hydro Operations:
 - Construction and rehabilitation activity in power sector and other infrastructure continues to be robust, leading to increased demand for equipment, materials, labour, and consulting and contracting services.
 - This could significantly increase costs for repair, rehabilitation and replacement projects.
- Demographic risk, especially in the engineering and skilled trades areas.
- Dam Safety (New Regulation risk) and Public Safety risks. Potential upgrade costs are not included in plan.
- Aboriginal Past Grievances - Cost of future settlements and additional claims may be higher than current provision.
- Ageing Plants: Asset integrity, reliability and safety at risk without continued re-investment.
- Structural and operational risks associated with:
 - Alkali Aggregate Reaction (AAR) induced concrete growth at Otto Holden, Saunders, Manitou Falls, Pine Portage, Chats Falls and Frederickhouse Dam.
 - Ageing wood stave and steel penstocks at Nipissing GS and Matabitchuan GS.
- Environmental risk associated with Ontario Endangered Species Act and Federal Species at Risk Act (compliance may require mitigation costs and impacts on production/revenue)
- Risks/impacts on Hydro production and reliability (generating equipment and sluice gates) of increasing Surplus Baseload Generation (SBG) situation in Ontario

The above risks are mitigated through programs, prudent asset management strategies and managed systems incorporated in this Business Plan. The risk profile of Hydro has not significantly increased due to new development projects. Project risks are mitigated by implementation of rigorous planning and project management systems/controls and revenue certainty from financial contracts (HESA's).

Appendix A

Additional Information

Station Statistics

HYDROELECTRIC PLANT LISTING BY PLANT GROUP

| Niagara Plant Group | No. of Units | Capacity (MW) | 30 Yr Avg Energy (GWH) | Age In 2009 (Years) | Capacity Factor | Ottawa-St. Lawrence Plant Group | No. of Units | Capacity (MW) | 30 Yr Avg Energy (GWH) | Age In 2009 (Years) | Capacity Factor | Central Hydro Plant Group | No. of Units | Capacity (MW) | 30 Yr Avg Energy (GWH) | Age In 2009 (Years) | Capacity Factor |
|--|--------------|----------------|------------------------|---------------------|-----------------|---|--------------|----------------|------------------------|---------------------|-----------------|---------------------------|--------------|---------------|------------------------|---------------------|-----------------|
| Decew Falls ND 1 | 4 | 23 | 107 | 111 | 54 | Arnprior | 2 | 82 | 147 | 33 | 21 | Auburn | 3 | 2 | 10 | 98 | 63 |
| Decew Falls NF23 | 2 | 144 | 1,037 | 65 | 82 | Barrett Chute | 4 | 176 | 302 | 67 | 20 | Big Chute | 1 | 10.0 | 51 | 16 | 58 |
| Sir Adam Beck I | 8 | 417 | 2,162 | 87 | 59 | Calabogie | 2 | 5 | 21 | 92 | 52 | Big Eddy | 2 | 8.0 | 37 | 68 | 53 |
| Sir Adam Beck II | 16 | 1,499 | 9,568 | 55 | 73 | Chats Falls | 4 | 96 | 531 | 78 | 63 | Bingham Chute | 2 | 1.0 | 4 | 86 | 48 |
| Sir Adam Beck PGS | 6 | 174 | -121 | 52 | 7 | Chenau | 8 | 144 | 734 | 59 | 58 | Coniston | 3 | 4.6 | 19 | 104 | 47 |
| TOTAL | 36 | 2,257 | 12,753 | 74 | 65 | Des Joachims | 8 | 429 | 2,264 | 59 | 60 | Crystal Falls | 4 | 8.4 | 43 | 88 | 58 |
| CNP Payback & Water Transfers | | | -500 | | | Mountain Chute | 2 | 170 | 298 | 42 | 20 | Elliott Chute | 1 | 1.6 | 5 | 80 | 37 |
| TOTAL (after CNP/WT) | | | 12,253 | | 62 | Otto Holden | 8 | 243 | 1,153 | 57 | 54 | Eugenia Falls | 3 | 6.1 | 23 | 94 | 43 |
| NUMBER OF DAMS & SPECIAL STRUCTURE 25 | | | | | | R.H. Saunders | 16 | 1,045 | 6,844 | 51 | 75 | Frankford | 4 | 2.6 | 14 | 96 | 61 |
| Note: Units 1 & 2 at SAB 1 are deregistered in April 2009 (were 25 Hz units) | | | | | | Stewartville | 5 | 182 | 308 | 61 | 19 | Hagues Reach | 3 | 3.6 | 20 | 84 | 64 |
| | | | | | | TOTAL | 59 | 2,570.9 | 12,603 | 60 | 56 | Hanna Chute | 1 | 1.4 | 8 | 83 | 65 |
| | | | | | | NUMBER OF DAMS IN PLANT GROUP 45 | | | | | | Healey Falls | 3 | 11.8 | 72 | 96 | 70 |
| Northeast Plant Group | | | | | | Northwest Plant Group | | | | | | High Falls | 3 | 2.7 | 15 | 89 | 63 |
| Abitibi Canyon | 5 | 349 | 1,340 | 76 | 44 | Aguasabon | 2 | 51 | 291 | 61 | 65 | Lakefield | 1 | 1.8 | 7 | 81 | 47 |
| Harmon | 2 | 141 | 632 | 44 | 51 | Alexander | 5 | 68 | 428 | 79 | 72 | McVittie | 2 | 2.8 | 11 | 97 | 47 |
| Hound Chute | 0 | 0 | 0 | 0 | Re dev. | Cameron Falls | 7 | 90 | 530 | 88 | 67 | Merrickville | 2 | 1.7 | 6 | 94 | 39 |
| Indian Chute | 2 | 3 | 16 | 85 | 63 | Caribou Falls | 3 | 91 | 515 | 51 | 64 | Meyersberg | 3 | 5.2 | 34 | 85 | 75 |
| Kipling | 2 | 157 | 633 | 43 | 46 | Ear Falls | 4 | 17 | 115 | 79 | 77 | Nipissing | 2 | 1.8 | 9 | 100 | 58 |
| Little Long | 2 | 133 | 555 | 46 | 48 | Kakabeka Falls | 4 | 25 | 143 | 103 | 66 | Ragged Rapids | 2 | 8.3 | 40 | 71 | 55 |
| Lower Notch | 2 | 274 | 400 | 38 | 17 | Manitou Falls | 5 | 73 | 392 | 53 | 61 | Ranney Falls | 3 | 10.4 | 52 | 87 | 57 |
| Lower Sturgeon | 0 | 0 | 0 | 0 | Re dev. | Pine Portage | 4 | 142 | 791 | 59 | 64 | Seymour | 5 | 5.7 | 32 | 100 | 65 |
| Matabitichuan | 4 | 10 | 52 | 99 | 62 | Silver Falls | 1 | 48 | 214 | 50 | 51 | Sidney | 4 | 4.4 | 25 | 98 | 66 |
| Otter Rapids | 4 | 182 | 707 | 48 | 44 | Whitedog Falls | 3 | 68 | 392 | 51 | 66 | Sills Island | 2 | 1.8 | 9 | 109 | 54 |
| Sandy Falls | 0 | 0 | 0 | 0 | Re dev. | Lac Seul | 1 | 12 | 52 | 1 | 49 | South Falls | 3 | 5.0 | 26 | 102 | 60 |
| Smoky Falls* | 4 | 52 | 377 | 85 | 82 | TOTAL | 39 | 684 | 3861 | 61 | 64 | Stinson | 2 | 5.4 | 23 | 84 | 49 |
| Wawatim | 4 | 11 | 51 | 97 | 54 | NUMBER OF DAMS IN PLANT GROUP 54 | | | | | | Trethewey Falls | 1 | 1.8 | 9 | 80 | 60 |
| TOTAL | 31 | 1,312.1 | 4,763 | 51 | 41 | NUMBER OF DAMS IN DIVISION 66 | | | | | | TOTAL | 65 | 119.8 | 607 | 87 | 58 |

NUMBER OF DAMS IN PLANT GROUP 41

41

NUMBER OF DAMS IN DIVISION 66

66

Total Capacity (MW) 6,943

Average Energy (TWh) 34.7

Total Number of Plants 65

Total Number of Dams 231

Avg. Age of Plants(yr) 70

Number of Units 230

“Portfolio Approach” to Asset Management

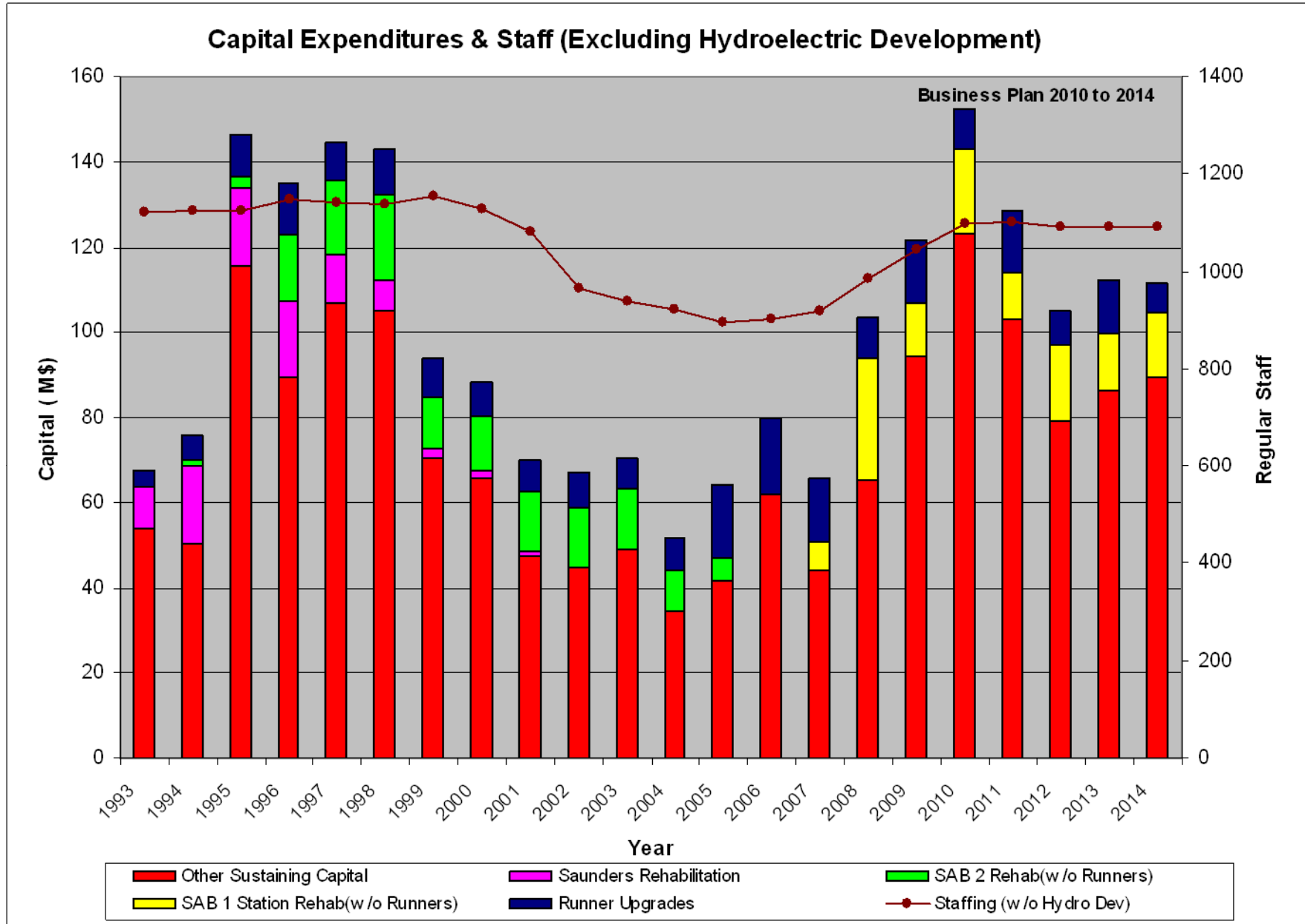
- Large portfolio of Hydro stations/units of varying vintage, technology and design makes it a challenge to prioritize maintenance and investments
- Portfolio of hydroelectric assets classified into 5 asset classes:
 - 1) Flagship
 - 2) Workhorse
 - 3) Middle of the Pack
 - 4) Small Plants
 - 5) Marginal Plants
- Stations in each asset class have similar characteristics/attributes & priorities.
- Provides asset management framework for:
 - 1) Determination of business priorities
 - 2) Assignment of risk tolerance
 - 3) Allocation of investment resources
 - 4) Determination of maintenance priorities (LEM)
- Economic value vs risk was used to classify stations into each asset class (risks include operational/environmental, condition, future investment, etc)

Prioritization Matrix - Projects and Maintenance Activities

| Asset Class | Stations | | | | Business Objectives (Work Categories) | | | | Value Enhancing or Improvement |
|---------------------------|----------------|---------------|-----------------|----------------|---|-------------------------|------------|----------------|--------------------------------|
| | | | | | Regulatory and Obligations (See Note 2) | Maintain Condition (MC) | | | |
| | | | | | | Asset Protection | Production | Non-production | |
| Flagship | SAB II | R.H. Saunders | Des Joachims | SAB 1 | 1 | 2 | 3 | 8 | NPV, IRR & PAYBACK |
| Workhorse | Abitibi Canyon | DeCew NF23 | Otto Holden | Otter Rapids | 1 | 2 | 4 | 9 | NPV, IRR & PAYBACK PERIOD |
| | Pine Portage | Lower Notch | Kipling | Chenaux | | | | | |
| | Harmon | Little Long | Mountain Chute | SAB PGS | | | | | |
| | Caribou Falls | Stewartville | Whitedog | Silver Falls | | | | | |
| | Aguasabon | | | | | | | | |
| Middle of the Pack | Barrett Chute | Chats Falls | Alexander | Manitou Falls | 1 | 2 | 5 | 10 | NPV, IRR & PAYBACK PERIOD |
| | Cameron Falls | Smoky Falls | Amprior | Lac Seul | | | | | |
| | Kakabeka Falls | DeCew ND1 | Ear Falls | | | | | | |
| Small Plants | Healey Falls | Big Chute | Ragged Rapids | Matabitchuan | 1 | 6 | 7 | 13 | NPV, IRR & PAYBACK PERIOD |
| | Ranney Falls | Big Eddy | Sidney | Meyersberg | | | | | |
| | Seymour | South Falls | Crystal Falls | Indian Chute | | | | | |
| | Eugenia | Frankford | Trethewey Falls | Hagues Reach | | | | | |
| | High Falls | Hanna Chute | Sills Island | Auburn | | | | | |
| | Stinson | McVittie | Coniston | Merrickville | | | | | |
| | Lakefield | | | | | | | | |
| Marginal | Hound Chute | Calabogie | Wawaitin | Lower Sturgeon | 1 | 11 | 12 | 14 | NPV, IRR & PAYBACK PERIOD |
| | Sandy Falls | Bingham Chute | Elliott Chute | Nipissing | | | | | |

1. Projects are assigned a priority in the Work Program Catalogue/Project Listing by applying this matrix in order to establish the relative importance of projects.
 2. Regulatory/Obligations category includes expenditures required to satisfy contractual obligations, dam safety requirements, health and safety regulations, environmental regulations, and corporate policy. It is expected that all projects in this category will be funded or corrective action be taken.
 3. Value enhancing or Performance Improvement projects, are to be assessed on an individual basis and must meet corporate financial guidelines.
 4. Refer to the "Business Objectives/Work Categories - Definitions" for a description of what is included in each category.
 5. Plants highlighted in red are being redeveloped.

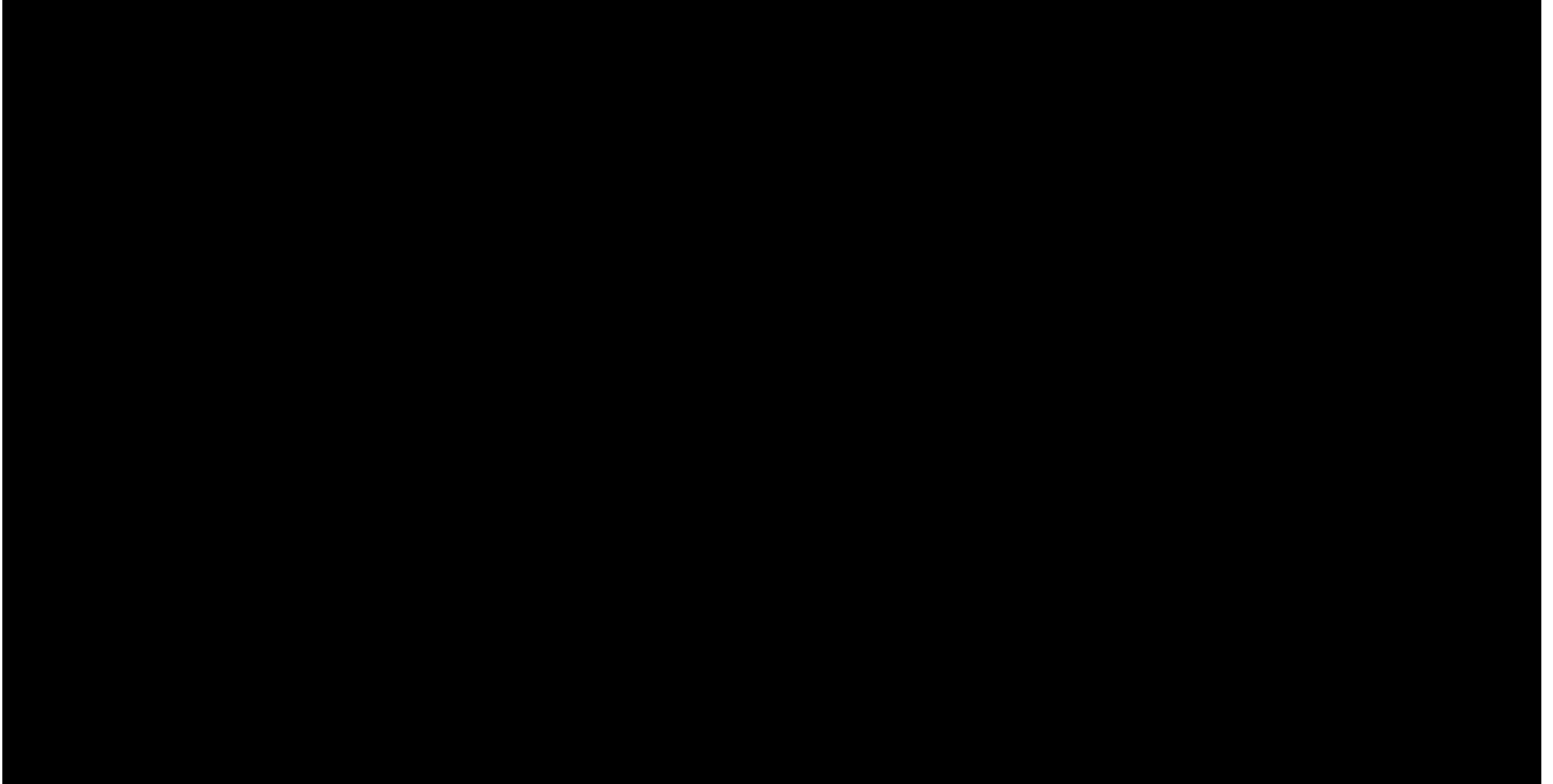
Capital Investments (Past, Present & Future)



Hydro Revenue, Cost, Staffing and Performance Summary

| HYDRO TOTAL | 2009 Forecast | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------------|-------------|-------------|-------------|-------------|-------------|
| Energy TW.h | 36 | 34.1 | 34.4 | 33.8 | 34.4 | 36.0 |
| Total Revenue (M\$) | | | | | | |
| OM&A (M\$) | | | | | | |
| - Base | | | | | | |
| - Projects (Totals from project listings) | | | | | | |
| Capital & MFA (M\$) | | | | | | |
| - MFA | | | | | | |
| - Projects (Totals from project listings) | | | | | | |
| Total Regular Staff at YE | 1077 | 1138 | 1144 | 1130 | 1131 | 1132 |
| - PWU | 697 | 729 | 733 | 720 | 723 | 722 |
| - Society | 285 | 306 | 307 | 306 | 304 | 306 |
| - Management Group | 95 | 103 | 104 | 104 | 104 | 104 |
| Temporary Staff FTEs | 12 | 16 | 16 | 16 | 16 | 16 |
| Fuel/GRC & Other Water Rentals (M\$) | 365 | 353 | 358 | 357 | 353 | 347 |
| Total Gross Labour (\$M) | 145 | 154 | 161 | 169 | 173 | 179 |
| - Total Gross Regular | 143 | 152 | 159 | 167 | 171 | 177 |
| - Total Gross Temporary & Other | 2 | 2 | 2 | 2 | 2 | 2 |
| - Overtime | 7 | 7 | 8 | 8 | 8 | 9 |
| - Overtime (% of Gross labour) | 5 | 4.9 | 4.9 | 4.9 | 4.9 | 5.0 |
| Availability Factor % | 93.1 | 91.0 | 92.4 | 92.6 | 92.3 | 92.8 |
| Equivalent Forced Outage Rate (EFOR) % | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Scheduled Outage Factor (SOF) % | 5.7 | 7.8 | 6.4 | 6.2 | 6.5 | 6.0 |
| Incapability Factor % | 6.9 | 9.0 | 7.6 | 7.4 | 7.7 | 7.2 |
| OM&A UEC (\$/MW.h) | | | | | | |
| FUEC (\$/MW.h) (GRC+Water Rentals) | | | | | | |
| PUEC (\$/MW.h) (Operations) | | | | | | |
| Contribution Margin (M\$) | | | | | | |
| Capacity (MW) | 6943 | 6995 | 7000 | 6966 | 7228 | 7484 |

OM&A And Capital - Year Over Year Changes (2009 to 2010)

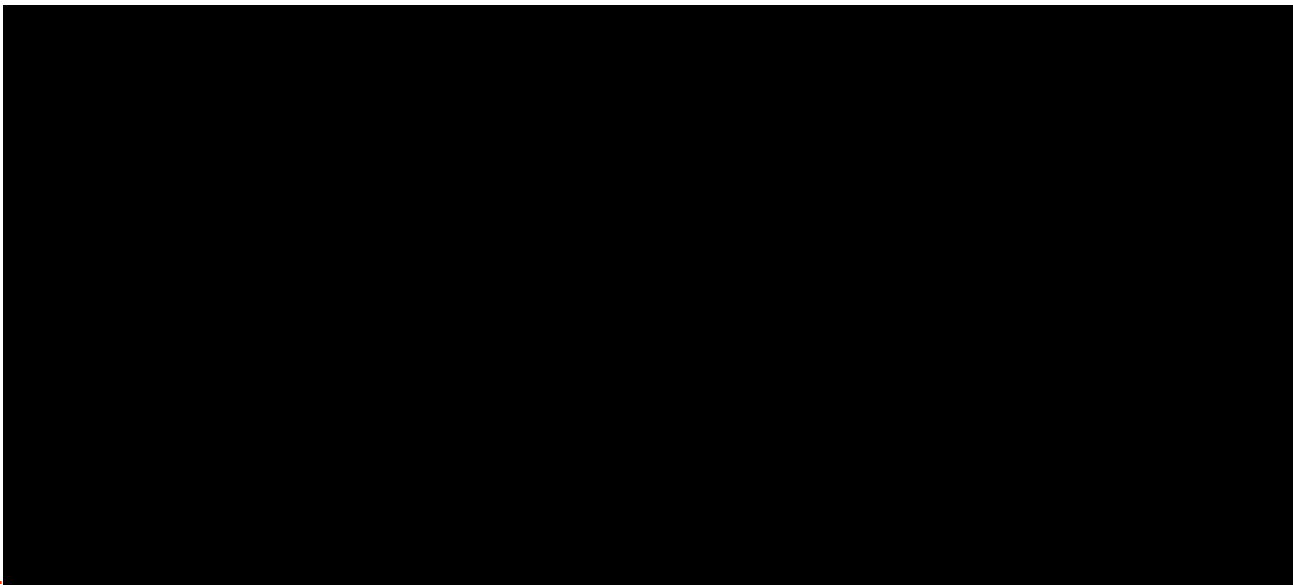


Capacity Changes During Planning Period

| Hydro Capacity Summary | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Change (2010 to 2014) |
|---|-------|-------|-------|-------|-------|-------|-----------------------|
| TOTAL CAPACITY AT BEGINNING OF YEAR (MW) | 6,961 | 6,943 | 6,996 | 7,000 | 6,966 | 7,228 | |
| Runner Upgrade Program | 11.2 | 12.6 | 4.4 | 18.8 | 18.0 | 12.1 | 65.9 |
| SAB 1 G7 Conversion (25 Cycle to 60 Cycle-does not incl. runner upgrade portion) | 54.6 | | | | | | 0.0 |
| SAB 1 (Decommissioning of 25 cycle system - G1 & G2) | -92.0 | | | | | | 0.0 |
| Lake Gibson | | | | | | | |
| Upper Mattagami Redevelopment | | | | | | | |
| Sandy Falls | | | | | | | |
| Lower Sturgeon | | | | | | | |
| Wawaitin | | | | | | | |
| Hound Chute | | | | | | | |
| Lower Mattagami Redevelopment | | | | | | | |
| Little Long | | | | | | | |
| Harmon | | | | | | | |
| Kipling | | | | | | | |
| Smoky Falls | | | | | | | |
| Mattagami Lake Dam | | | | | | | |
| Newpost Creek | | | | | | | |
| Healey Falls | | | | | | | |
| Ranney Falls | | | | | | | |
| Lac Seul GS | | | | | | | |
| Long Lake | | | | | | | |
| Little Jackfish | | | | | | | |
| Lake Gibson | | | | | | | |
| South Falls | | | | | | | |
| TOTAL CAPACITY AT END OF YEAR (MW) | | | | | | | |

Energy Production Plan (Impacts of Surplus Baseload Generation)

| Business Plan 2010-2014 Energy Production Forecast with SBG | | | | | |
|---|--------------|--------------|--------------|--------------|--------------|
| PLANT GROUP | 2010 TWh | 2011 TWh | 2012 TWh | 2013 TWh | 2014 TWh |
| Niagara Plant Group Total | 12.99 | 13.23 | 13.21 | 13.27 | 14.14 |
| Group SBG | 0.18 | 0.46 | 0.80 | 0.34 | 0.75 |
| Niagara PG Adjusted SBG Group Total | 12.81 | 12.77 | 12.41 | 12.93 | 13.39 |
| OSPG Group Total | 12.56 | 12.61 | 12.61 | 12.53 | 12.56 |
| Group SBG | 0.00 | 0.02 | 0.05 | 0.02 | 0.03 |
| OSPG Adjusted SBG Group Total | 12.56 | 12.60 | 12.55 | 12.51 | 12.54 |
| Northeast Plant Group Total | | | | | |
| Group SBG | | | | | |
| NEPG Adjusted SBG Group Total | | | | | |
| Northwest Plant Group Total | | | | | |
| Group SBG | | | | | |
| NWPG Adjusted SBG Group Total | | | | | |
| Central Hydro Plant Group Total | | | | | |
| Group SBG | | | | | |
| CHPG Adjusted SBG Group Total | | | | | |
| HYDROELECTRIC TOTAL | | | | | |
| Total SBG | | | | | |
| ADJUSTED SBG HYDROELECTRIC TOTAL | | | | | |



Appendix B

Regulated Asset Information

Hydro Regulated Asset Performance & Cost Summary

| Regulated Hydro (Includes Hydro Central Office Allocations) | 2009 Forecast | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---------------|-------------|-------------|-------------|-------------|-------------|
| Energy TW.h | 19.5 | 19.3 | 19.4 | 19.0 | 19.6 | 20.3 |
| Total Revenue (M\$) | 733 | 713 | 741 | 730 | 804 | 837 |
| OM&A (M\$) | 67 | 67 | 78 | 72 | 71 | 76 |
| - Base | 59.7 | 61.9 | 68.7 | 62.2 | 63.7 | 67.0 |
| - Projects (Totals from project listings) | 6.9 | 5.3 | 9.7 | 10.0 | 7.7 | 8.7 |
| Capital & MFA (M\$) | 41 | 54 | 40 | 37 | 32 | 29 |
| - MFA | 0.2 | 0.2 | 1.2 | 0.3 | 0.3 | 0.3 |
| - Projects (Totals from project listings) | 40.5 | 53.3 | 38.7 | 36.5 | 31.6 | 28.4 |
| Total Regular Staff at YE | 313 | 319 | 318 | 307 | 309 | 309 |
| Temporary Staff FTEs | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Fuel/GRC & Other Water Rentals (M\$) | 263 | 266 | 269 | 269 | 267 | 260 |
| Total Gross Labour (\$M) | 42 | 43 | 45 | 47 | 47 | 49 |
| - Total Gross Regular | 40.9 | 42.3 | 44.3 | 46.2 | 46.2 | 48.3 |
| - Total Gross Temporary & Other | 0.8 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 |
| - Overtime | 2.2 | 2.2 | 2.4 | 2.5 | 2.5 | 2.6 |
| - Overtime (% of Gross labour) | 5.4 | 5.2 | 5.3 | 5.4 | 5.4 | 5.3 |
| Availability Factor % | 93.8 | 90.3 | 90.8 | 90.7 | 91.7 | 92.0 |
| Equivalent Forced Outage Rate (EFOR) % | 1.4 | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| Scheduled Outage Factor (SOF) % | 5.1 | 8.7 | 8.1 | 8.3 | 7.3 | 6.9 |
| Incapability Factor % | 6.2 | 9.7 | 9.2 | 9.3 | 8.3 | 8.0 |
| OM&A UEC (\$/MW.h) | 3.4 | 3.5 | 4.0 | 3.8 | 3.6 | 3.7 |
| FUEC (\$/MW.h) (GRC+Water Rentals) | 13.5 | 13.7 | 13.9 | 14.1 | 13.6 | 12.8 |
| PUEC (\$/MW.h) | 16.9 | 17.2 | 17.9 | 17.9 | 17.3 | 16.5 |
| Contribution Margin (M\$) | 403 | 380 | 393 | 390 | 465 | 502 |
| Capacity (MW) | 3302 | 3312 | 3312 | 3315 | 3320 | 3322 |

Niagara Plant Group

| Niagara Plant Group | 2009 Forecast | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|------------------|-------------|-------------|-------------|-------------|-------------|
| Energy TW.h | 12.4 | 12.4 | 12.4 | 12.1 | 12.7 | 13.4 |
| Total Revenue (M\$) | 465 | 457 | 474 | 463 | 519 | 551 |
| OM&A (M\$) | 45.8 | 44.4 | 53.4 | 46.3 | 47.7 | 50.1 |
| - Base | 40.6 | 40.3 | 46.7 | 40.3 | 41.4 | 43.9 |
| - Projects | 5.2 | 4.0 | 6.7 | 6.0 | 6.3 | 6.3 |
| Capital & MFA (M\$) | 28.0 | 36.2 | 30.7 | 30.9 | 25.3 | 25.2 |
| - MFA | 0.2 | 0.2 | 1.2 | 0.3 | 0.3 | 0.3 |
| - Projects | 27.8 | 36.0 | 29.5 | 30.6 | 25.0 | 24.9 |
| Total Regular Staff at YE | 243 | 251 | 250 | 239 | 241 | 241 |
| Temporary Staff FTEs | 0 | 0 | 0 | 0 | 0 | 0 |
| GRC & Other Water Rentals (M\$) | 167 | 172 | 175 | 174 | 173 | 166 |
| Total Gross Labour (\$M) | 33 | 34 | 35 | 37 | 37 | 38 |
| - Total Gross Regular | 31.9 | 33.4 | 35.0 | 36.5 | 36.2 | 37.9 |
| - Total Gross Temporary & Other | 0.7 | 0.3 | 0.3 | 0.3 | 0.3 | 0.4 |
| - Overtime | 1.9 | 1.9 | 2.0 | 2.1 | 2.2 | 2.2 |
| - Overtime (% of Gross labour) | 6.0 | 5.7 | 5.8 | 5.8 | 6.0 | 5.8 |
| Availability Factor % | 89.5 | 88.2 | 89.5 | 88.3 | 90.0 | 89.1 |
| Equivalent Forced Outage Rate (EFOR) % | 1.5 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Scheduled Outage Factor (SOF) % | 9.3 | 9.9 | 9.0 | 10.2 | 8.5 | 9.5 |
| Incapability Factor % | 10.5 | 11.8 | 10.5 | 11.7 | 10.0 | 10.9 |
| OM&A UEC (\$/MW.h) | 3.7 | 3.6 | 4.3 | 3.8 | 3.8 | 3.7 |
| GRC UEC (\$/MW.h) (GRC+Water Rentals) | 13.5 | 13.9 | 14.1 | 14.4 | 13.7 | 12.4 |
| PUEC (\$/MW.h) | 17.2 | 17.4 | 18.4 | 18.3 | 17.5 | 16.1 |
| Capacity (MW) | 2257 | 2267 | 2267 | 2270 | 2275 | 2277 |

Key Programs & Issues

- Major rehabilitation/upgrade of SAB1 G9 in 2009/2010, G10 in 2013, G3 in 2012.
- Civil rehabilitation projects for SAB1 continue through planning period (e.g. concrete restoration, roof replacement, tailrace bridge and piers, etc.)
- DeCew Falls ND1 G8 scheduled for overhaul in 2011. Penstock replacement 2009 to 2011. Station Protection and control upgrades scheduled for 2011/2012.
- SAB PGS Unit rehabilitation on G2-5 planned for 2011-2014. PGS Unit transformers also scheduled for replacement 2009-11. Unit breakers and governors planned for replacement 2011-13.
- SAB 2 Station Service System Replacement 2010/2011 and Governor system upgrade 2013/2014
- Development and implementation of Niagara Bridge program including maintenance, divestment and investment ongoing. Divestiture of four bridges being pursued.
- Optimization Initiative – Niagara Optimization Working Group
- Continue to build and improve public franchise.
- Manage risks of equipment failures:
 - PGS Reliability & Turbine Leakage.
 - PGS Transformer failure. Replacement planned in 2010/11.

Saunders GS

| Saunders GS (includes OSPG Support Costs) | 2009 Forecast | 2010 | 2011 | 2012 | 2013 | 2014 |
|--|---------------|-------------|-------------|-------------|-------------|-------------|
| Energy TW.h | 7.1 | 6.9 | 7.0 | 7.0 | 7.0 | 7.0 |
| Total Revenue (M\$) | 268 | 255 | 267 | 267 | 285 | 286 |
| OM&A (M\$) | 16.2 | 13.6 | 16.0 | 17.6 | 15.4 | 16.7 |
| - Base | 14.6 | 12.4 | 13.1 | 13.6 | 14.0 | 14.3 |
| - Projects (Totals from project listings) | 1.7 | 1.2 | 3.0 | 4.0 | 1.4 | 2.4 |
| Capital & MFA (M\$) | 12.7 | 17.3 | 9.2 | 5.9 | 6.6 | 3.4 |
| - MFA | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| - Projects (Totals from project listings) | 12.7 | 17.3 | 9.2 | 5.9 | 6.6 | 3.4 |
| Total Regular Staff at YE (Saunders Only) | 71 | 68 | 68 | 68 | 68 | 68 |
| Temporary Staff FTEs | 0.0 | 1 | 1 | 1 | 1 | 1 |
| GRC & Other Water Rentals (M\$) | 96 | 94 | 94 | 94 | 94 | 94 |
| Total Gross Labour (M\$) | 9 | 10 | 10 | 11 | 11 | 11 |
| - Total Gross Regular | 8.6 | 9.8 | 10.2 | 10.7 | 11.0 | 11.4 |
| - Total Gross Temporary & Other | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| - Overtime | 0.4 | 0.3 | 0.3 | 0.3 | 0.4 | 0.4 |
| - Overtime (% of Gross labour) | 4.2 | 3.2 | 3.1 | 3.1 | 3.2 | 3.2 |
| Availability Factor % | 95.5 | 93.7 | 94.2 | 96.1 | 96.3 | 98.9 |
| Equivalent Forced Outage Rate (EFOR) % | 1.1 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Scheduled Outage Factor (SOF) % | 3.6 | 6.0 | 5.5 | 3.6 | 3.4 | 0.8 |
| Incapability Factor % | 4.5 | 6.3 | 5.8 | 3.9 | 3.7 | 1.1 |
| OM&A UEC (\$/MW.h) | 2.3 | 2.0 | 2.3 | 2.5 | 2.2 | 2.4 |
| FUEC (\$/MW.h) | 13.6 | 13.5 | 13.5 | 13.5 | 13.5 | 13.5 |
| PUEC | 15.8 | 15.5 | 15.8 | 16.1 | 15.7 | 15.9 |
| Capacity (MW) | 1045 | 1045 | 1045 | 1045 | 1045 | 1045 |

Key Programs & Issues

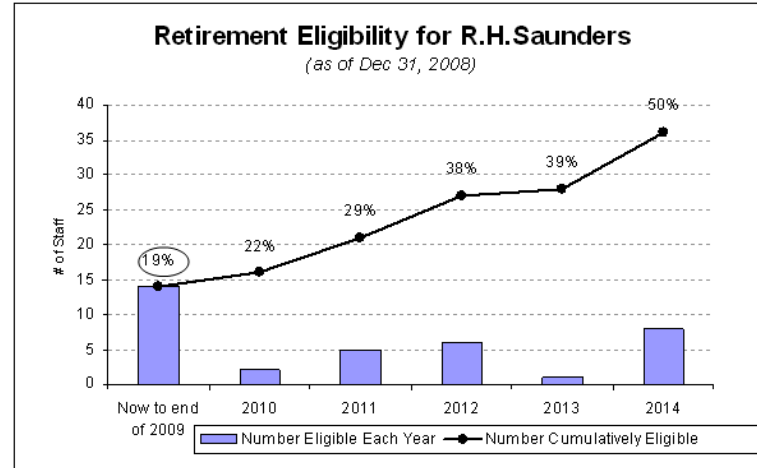
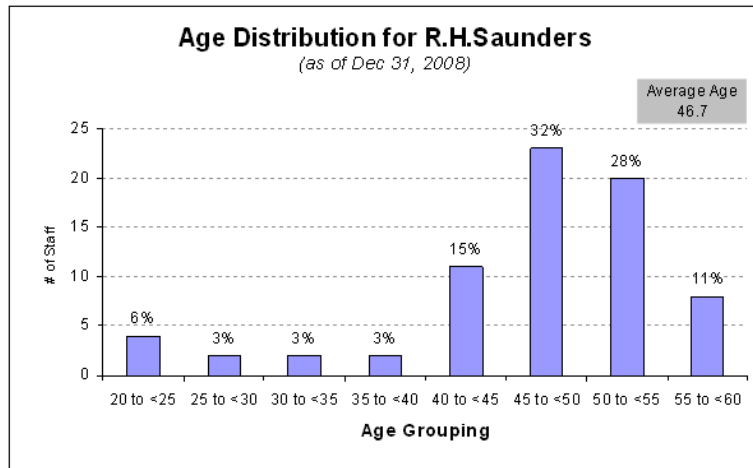
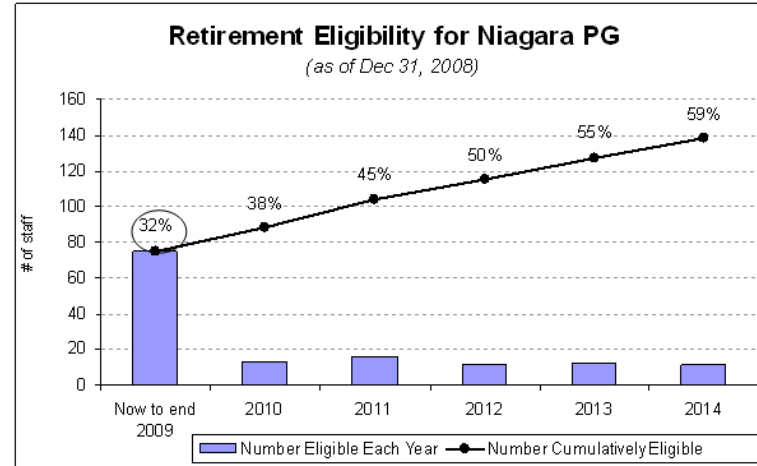
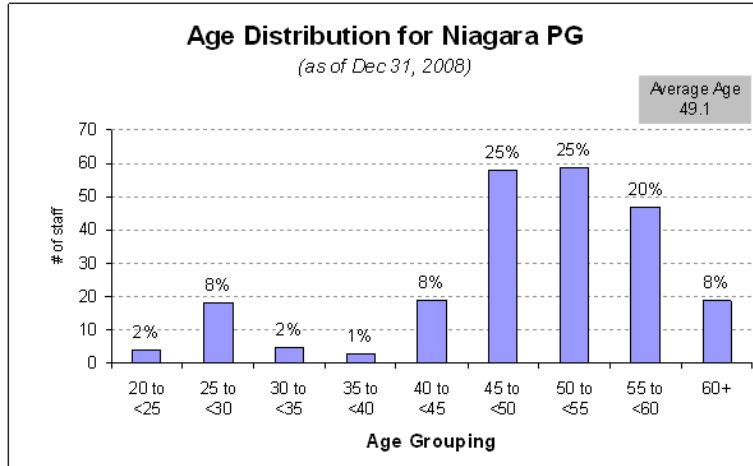
- Protection and Controls replacement project (2009 to 2011).
- St. Lawrence Power Development Visitor Centre to be completed in 2010 (part of Saunders GS capital costs)
- Barnhardt Island Bridge Repainting – Joint Works (NYPA Project) in 2012
- Ice Sluices Deck and Steel Support Beam Rehabilitation in 2011
- NYPA Joint Works including the Barnhardt Island Bridge repairs, inspection of Long Sault Dam and crane lead abatement totals \$5.5M

Issues/Risks:

- American eel mitigation funding included at (\$540-\$685k per year). Improved Eel Ladder was installed in 2009.
- Saunders concrete growth rate faster than expected. Monitoring continues. Could require re-slotting in 3 to 8 yrs.

Human Resources – Demographics (Regulated Plants)

- 32% of Niagara staff are eligible to retire by end of 2009 and 59% by end of 2014. Demographics and retirement eligibility at R.H. Saunders are better than Niagara, but still an issue.



- Due to the staff shortages in engineering / project support and some trades areas, it has been a challenge to complete the planned 2009 work program in Niagara.
- To address the demographic issue, Niagara is adding apprentices and operating trainees, as well as engineers and contract monitors. The apprentices will overlap with experienced trades staff for training and knowledge transfer. Staff complement at Niagara will increase from 243 in 2009 to 250 in 2011, and decline to 241 in 2013/4.