

**Board Staff Interrogatory #041**

**Ref:** Ex. F1-T2-S1, Tables 1 and 3

**Issue Number: 6.1**

**Issue:** Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

**Interrogatory**

From 2008 – 2012, the Niagara Plant Group OM&A costs increase by about 19% (Table 1). This includes an increase in 2012 relative to 2011 following the conclusion of the Niagara Bridge Divestiture Program as referenced in the application (F1-T2-S2, p.2). The number of staff FTEs in the Niagara Plant Group also increase by 8% over the same 2008 – 2012 period, which includes a minor FTE reduction following the conclusion of the Niagara Bridge Divestiture Program (Table 3). Please identify the primary drivers underlying these OM&A cost and FTE increases and provide an explanation for each.

**Response**

The percentages quoted in this interrogatory appear to refer to the 2008 versus 2011 cost and staff increases, rather than 2008 versus 2012 comparison stated in the question (see Table 1 below). The increase to Base OM&A in 2011 is mostly due to the bridge divestiture program which is described in Ex. F1-T2-S2, page 2, lines 18-21. Removing the bridge divestiture program from Base OM&A, the 2011 plan shows a 4.5 per cent increase over 2008. The 4.5 per cent increase is mainly associated with increased FTEs in the Base OM&A program in 2011.

| <b>Table 1<br/>Niagara Plant Group Base OM&amp;A (\$M)</b>                        |                        |                        |                        |                        |                      |                      |
|-----------------------------------------------------------------------------------|------------------------|------------------------|------------------------|------------------------|----------------------|----------------------|
|                                                                                   | <b>2007<br/>Actual</b> | <b>2008<br/>Actual</b> | <b>2009<br/>Actual</b> | <b>2010<br/>Budget</b> | <b>2011<br/>Plan</b> | <b>2012<br/>Plan</b> |
| Base OM&A                                                                         | 38.3                   | 44.6                   | 46.7                   | 47.2                   | 53.5                 | 46.3                 |
| Subtract: Bridge Divestiture Program                                              | 0.0                    | 0.0                    | 4.0                    | 1.8                    | 6.9                  | 0.0                  |
| Base OM&A (excluding Bridge Divestiture Program)                                  | 38.3                   | 44.6                   | 42.7                   | 45.4                   | 46.6                 | 46.3                 |
| Increase/ (Decrease) in Base OM&A compared to 2008 (%)                            |                        |                        | 4.7                    | 5.8                    | 20.0                 | 3.8                  |
| Increase/ (Decrease) in Base OM&A (excluding bridge program) compared to 2008 (%) |                        |                        | (4.3)                  | 1.8                    | 4.5                  | 3.8                  |

1 The FTE table (Ex. F1-T2-S1, Table 3) does not only relate to Base OM&A. Table 3 presents  
2 total plant staff, including staff deployed on Base OM&A, OM&A Projects, and Capital  
3 Projects.

4  
5 The primary driver for the increase in FTEs in the Niagara Plant Group is the demographic  
6 concern. The Plant Group has developed a succession plan in order to take a proactive  
7 approach to mitigating the risk associated with the aging demographic. The positions  
8 determined to be at the greatest risk for retirements are: Electrical & Controls Technicians,  
9 Mechanical Technicians, Hydroelectric Operators, and Engineering staff. Apprentices and  
10 engineering trainees have been hired and continue to be hired in advance of expected  
11 retirements in order to allow time for training and knowledge transfer. The longer term plan is  
12 to reduce FTEs by attrition due to retirements.

**AMPCO Interrogatory #021**

**Ref:** Ex. F1-T1-S1

**Issue Number: 6.1**

**Issue:** Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

**Interrogatory**

- a) How much station service power has been or will be paid by the regulated hydro-electric business each year since 2005 through to the end of the test period? Please include a breakout of GA costs.
- b) Please provide an estimate of the impact of the AMPCO High 5 proposal as described in EB-2008-0272 if it were to apply during the test period.
- c) How was the \$1.2 million O&M reduction allocated to the regulated hydro-electric business allocated internally within the regulated business?

**Response**

a) At the prescribed hydroelectric stations, some electricity consumption is self-supplied (i.e., supplied directly from the generators), and some consumption is supplied from the Independent Electricity System Operator ("IESO") -controlled grid (i.e., grid withdrawals). As outlined in OPG's response to the interrogatory in Ex. L-1-088 part b), the IESO does not meter self-supplied consumption but the IESO does meter grid withdrawals. All station electricity consumption, self-supplied or grid withdrawals, is paid by OPG:

- Self-supplied consumption reduces the station electricity output into the IESO-controlled grid. Because this consumption is not metered by the IESO, it does not attract non-energy load charges and OPG does not explicitly track the value of this consumption.
- Grid withdrawals are metered by the IESO and they attract non-energy load charges.

Table 1 below outlines the value of grid withdrawals by calendar year from 2005 - 2009. The first column shows the value of grid withdrawals. The second column shows the total non-energy load charges while the third column shows the Global Adjustment component included in the total non-energy load charges.

**Table 1**  
**Prescribed Hydroelectric Grid Withdrawal Values: 2005 – 2009**

| <b>Year</b> | <b>Value of withdrawals (\$M)</b> | <b>Total Non-Energy Load Charges (Including Global Adjustment)<sup>1</sup> (\$M)</b> | <b>Global Adjustment (Included In Total Non-Energy Load Charges) (\$M)</b> |
|-------------|-----------------------------------|--------------------------------------------------------------------------------------|----------------------------------------------------------------------------|
| 2005        | 10.7                              | 4.5                                                                                  | (3.0) <sup>2</sup>                                                         |
| 2006        | 9.9                               | 4.4                                                                                  | 1.3                                                                        |
| 2007        | 9.8                               | 3.4                                                                                  | 1.3                                                                        |
| 2008        | 9.9                               | 4.3                                                                                  | 1.9                                                                        |
| 2009        | 10.9                              | 12.7                                                                                 | 9.6                                                                        |

In Table 2 below, an explicit forecast of the cost of grid withdrawals is not available. The first column shows the total non-energy charge forecast while the second column shows the Global Adjustment component of the total forecast non-energy load charge.

**Table 2**  
**Prescribed Hydroelectric Forecast**  
**Non-Energy Costs: 2010 – 2012**

| <b>Year</b> | <b>Total Non-Energy Load Charges (Including Global Adjustment)<sup>3</sup> (\$M)</b> | <b>Global Adjustment Charges (\$M)</b> |
|-------------|--------------------------------------------------------------------------------------|----------------------------------------|
| 2010        | 10.1                                                                                 | 6.3                                    |
| 2011        | 11.6                                                                                 | 7.8                                    |
| 2012        | 12.8                                                                                 | 9.0                                    |

- b) OPG has no estimate of the impact on its station service costs of this proposal. OPG notes that this matter is before the OEB in EB-2010-0002 and that Hydro One suggests an implementation date of January 1, 2012 in the event that the OEB decides to adopt this proposal.
- c) The OM&A cost reductions described in Ex. F1-T1-S1, page 2, lines 6-14 affect only 2010. For the regulated hydroelectric stations, it was the Niagara Plant Group that identified an opportunity to advance \$1.2M of work on the repairs to the Sir Adam Beck I Generating Station powerhouse concrete into 2009.

<sup>1</sup> Values for 2005 to 2007 from EB-2007-0905, Ex. F3-T1-S1, Table 13. Values for 2008 – 2009 from EB-2010-0008, Ex. F4-T4-S1, Table 2.

<sup>2</sup> Note that the Global Adjustment in 2005 was a credit and not a cost.

<sup>3</sup> Values for EB-2010-0008, Ex. F4-T4-S1, Table 2.

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Deferral and Variance Accounts, Payment Amounts and Regulatory Treatments

**CCC Interrogatory #024**

**Ref:** Ex. F1-T4-S1, Table 1

**Issue Number: 6.1**

**Issue:** Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

**Interrogatory**

Please recast Table 1 setting out forecast amounts for the Gross Revenue Charge for the years 2007-2010.

**Response**

The requested information is provided in the Application at Ex. F1-T4-S2, Table 1, which shows both the actual and forecast (budget) amounts of Gross Revenue Charge ("GRC").

**PWU Interrogatory #005**

**Ref:** (a) The Ontario Power Authority website states:

Though wind energy is relatively new to Ontario, it is a growing source of electricity generation in the province. Ontario currently has more than 300 MW of wind power in service with an additional 1,000 MW on the way.

(b) The Ontario Power Authority website states:

Ontario is Canada's first province to actively support the development of solar electricity generation projects through the Standard Offer Program, which will enable small, local, renewable energy producers to get into the energy market.

**Issue Number: 6.1**

**Issue:** Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

**Interrogatory**

What work programs/investments is OPG undertaking to maintain/enhance its load-frequency control performance at its regulated facilities in support of the expected increase in Ontario's supply mix of non-dispatchable wind and solar generation?

**Response**

OPG is continuing its maintenance program to sustain the load-frequency control, or Automatic Generator Control ("AGC"), mode of operation at the Sir Adam Beck II Generating Station. No enhancements are planned for load-frequency control during the test period.

**PWU Interrogatory #010**

**Ref:** Ex. F1,-T1-S1, page 3, lines 13-17 states:

Hydroelectric uses a structured portfolio approach to identify and prioritize projects for its investment program. Annual engineering reviews and plant condition assessments (conducted on a cycle of approximately seven to ten years) are performed to determine short-term and long-term expenditure requirements to sustain or improve each facility, and ensure continued safe operation.

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**Issue:** Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

**Interrogatory**

Please provide detailed descriptions of OPG's hydroelectric engineering review and plant condition assessment processes.

**Response**

Details of OPG's hydroelectric engineering review and plant condition assessment processes are provided below:

**Engineering Risk Assessment Program**

OPG's Hydroelectric Engineering Risk Assessment Program ("ERAP") is an annual technical review used to identify significant operational risks associated with plant equipment and systems in the hydroelectric business. This process systematically identifies, assesses and ranks the likelihood and consequence of safety, environmental and financial risks resulting from inadequate, obsolete or failed plant equipment or systems.

Each plant group within the hydroelectric business selects those systems that they believe present the highest risks to the business. Concurrence on the systems to be evaluated is obtained from the Chief Hydroelectric Engineer. The Chief Hydroelectric Engineer may also direct that strategic or emerging issues be included in the review. Subject matter experts from the Hydroelectric Engineering Division ("HED") are made available to assist the plant groups in their analysis. Subject matter experts are also made available from the Environmental Division to provide advice on environmental issues.

The selected systems are evaluated in-depth; risk profiles are developed; and mitigating action plans are formulated. A formal presentation of the current engineering risk profile is made to the Executive Vice President – Hydroelectric and Chief Hydroelectric Engineer annually highlighting the risks identified and the mitigation action plan. The status and effectiveness of mitigating plans from previous years are also reviewed. The objective is to

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review the high risk systems each year and systematically lower the risk of plant operation. All plant systems must be reviewed every five years.

Risk Rank is defined as the product of Likelihood of Occurrence and the Resulting Consequence. For each system considered, a risk profile is developed for each category of safety, environmental and financial loss. Environmental risk is assessed based on two components, spill risk (using the Spill Characterization and Risk Assessment tool) and other environmental risks. The higher of the two results is adopted as the environmental risk rank. Both likelihood of occurrence and resulting consequence are ranked 1 through 5, with the resulting product being between 1 through 25. The table below outlines the risk rank and resulting required actions.

Data to assess the condition and evaluate the risk of failures is obtained from sources such as current plant condition assessments, maintenance records, condition reports, inspection reports, test reports, operator, maintenance and engineering reports, incident reports, regulatory infractions, and developments in external utilities and industries. Conformance to applicable codes, acts and regulations and Hydroelectric Engineering Governance as well as reference to industry standards is also included in the assessment to demonstrate good engineering practice and due diligence.

| Risk Rank | Category  | Required Action (*)                                                                                                    |
|-----------|-----------|------------------------------------------------------------------------------------------------------------------------|
| 15 – 25   | Very High | Repair/replacement urgently carried out.                                                                               |
| 10 – 12   | High      | Plans put in place for repair/replacement at the earliest opportunity.                                                 |
| 5 – 9     | Medium    | Have plans, as appropriate, in place (e.g., condition monitoring and/or plans for possible future repair/replacement). |
| 1 – 4     | Low       | Continue to manage risk through the ERAP.                                                                              |

(\*) – Apply engineering judgement in establishing action plan. The objective is to minimize risk to the business.

#### Plant Condition Assessment

The Plant Condition Assessment ("PCA") is a thorough, multi-disciplinary, systems-based assessment of the physical condition of each hydroelectric generating station and that station's associated structures. The PCA provides a determination of the required repair, rehabilitation, modification, or replacement of the assessed facilities' various components and/or systems, in order to maintain the safety, reliable production capability, and viability of the facility for the next 30 years. PCAs are repeated on a seven year cycle.

PCAs are carried out on a station's structures, equipment and other components. Structures include the powerhouse and dams, water control structures, canals, tunnels, and roads,

bridges, and other structures (e.g., safety booms, ice booms) associated with the generating station under review.

For each of OPG's hydroelectric generating station (and associated structures), the PCA:

- provides a forecast of all required capital and non-standard OM&A investments over the next ten years. Base maintenance costs are not included.
- Identifies major investment requirements beyond ten years.
- Provides rigorous engineering-based rationale for the recommended investments.

Plant Condition Assessments are carried out by a multi-discipline team, having expertise in hydroelectric facilities' major components and systems. The team includes a PCA Coordinator, a PCA Lead Engineer for each discipline-specific team (Mechanical, Civil, and Electrical), PCA Investigators, and a PCA Plant Group Coordinator. Integrated into each discipline's assessment is a review of discipline-specific Health and Safety and Environmental issues.

Each Lead Engineer is responsible for the assessments of his disciplines' team of investigators. The Lead Engineer must be a professional engineer with a minimum of 10 years of engineering experience. This experience must include a minimum of five years experience in his/her specific discipline area of hydroelectric plant design, operation or maintenance.

Component-specific PCA checksheets guide the investigators and provide a detailed tool for the assessment of each system of the facility.

A common four level rating system (see below) ensures that the assessments are consistent both between disciplines, and between systems within a facility.

#### Common Condition Rating Scale

| Rating | Condition Description | Details                                                                                   | Remediation   |
|--------|-----------------------|-------------------------------------------------------------------------------------------|---------------|
| 4      | Good                  | Only minor deterioration or defects are evident.                                          | 20 plus years |
| 3      | Fair                  | Moderate deterioration. Function is still adequate.                                       | 7-20 years    |
| 2      | Poor                  | Serious deterioration of at least some portions of the equipment. Function is inadequate. | 2-7 years     |
| 1      | Unacceptable          | Extensive deterioration. Barely functional. Urgent need for remediation.                  | 0-2 years     |

Data is obtained from engineering and inspection records to develop a clear picture of the condition of the facility and support the site investigations. Site investigations include

1 interviews with site operating, maintenance, and supervisory personnel, a physical review  
2 and inspection of the system being assessed, and, where appropriate, outage inspections.

3  
4 The findings from each system assessment (as defined in the systems matrix) are reported  
5 following a standard format of system description, system assessment and  
6 recommendations. The recommendations identify the remedial work, its engineering basis,  
7 estimated costs, and the recommended timeframe. A discipline summary spreadsheet  
8 consolidates these recommendations, costs, and their timing (30-year timeframe) on a  
9 discipline basis, and a facility summary spreadsheet is then developed to roll the discipline  
10 costs into a single snapshot of the facilities' recommended remedial work and costs for the  
11 next 30 years. When complete, the PCAs are used as the basis for development of life cycle  
12 plans for the individual stations.

**PWU Interrogatory #011**

**Ref:** (a) Ex. F1-T2-S2, page 4, lines 10-11. In comparing 2009 Actual vs. 2009 budget OPG reports:

Higher than planned attrition and unfilled vacancies across the central support groups (resulting in lower labour costs).

(b) Ex. F1-T2-S2, page 4, lines 27-28. For 2009, in relation to the Niagara Group, OPG submits:

These costs have been offset by a reduction in labour burdens of \$0.2M and an overall reduction in labour costs due to staff vacancies of \$1.8M.

(c) Ex. F1-T2-S2, page 5, lines 28-30. In comparing 2008 Actual vs. 2008 budget OPG reports:

...and delays in filling staff vacancies across the central support groups, especially in Engineering and Hydroelectric Development.

(d) Ex. F1-T2-S2, page 8, line 15. In comparing 2007 Actual vs. 2007 budget for the hydroelectric central support groups OPG states:

Staffing under-variance due to staff departures and slower hiring (\$0.5M).

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**Interrogatory**

- a) Were OPG's works across the Niagara Plant Group, R.H. Saunders Generating Stations and the Hydroelectric Central Groups impacted by unfilled staff vacancies reported over the period 2007-2009? If so, please provide a description of OPG's efforts to manage unfilled vacancies.
- b) What is the current status of OPG's staff vacancies across the Niagara Plant Group, R.H. Saunders Generating Stations and the Hydroelectric Central Groups? Please indicate the number of current staff vacancies for each of the three groups.
- c) Has OPG eliminated vacant positions reported as unfilled over the period 2007-2009? Please indicate the number of vacant positions eliminated for each of the following three groups:
- Niagara Plant Group;
  - R.H. Saunders Generating Stations; and
  - Hydroelectric Central Groups.

- 1  
2 d) Is OPG planning to fill current staff vacancies for the Niagara Plant Group, R.H. Saunders  
3 Generating Stations and the Hydroelectric Central Groups over the period 2010-2012?  
4  
5

6 **Response**  
7

- 8 a) The Niagara Plant Group and Hydroelectric Central Support Groups have been impacted  
9 by staff vacancies over the 2007 – 2009 period. The Niagara Plant Group managed unfilled  
10 vacancies by hiring temporary employees to help facilitate the workload until regular staff  
11 could be hired. The Hydroelectric Central Support Groups have managed their unfilled  
12 vacancies by hiring temporary staff, staff on rotation from other parts of OPG, outsourcing  
13 some specialized technical work, and re-prioritizing some work. For the period 2007 –  
14 2009, R.H. Saunders Generating Station has not been impacted because the station was  
15 at or above staff complement levels.  
16  
17 b) The Niagara Plant Group currently (year-to-date July) has 17 vacant regular staff  
18 positions as compared to the approved 2010 – 2014 Business Plan. There are no  
19 vacancies at R.H. Saunders Generating Station as the staff level is above the approved  
20 complement. The Hydroelectric Central Support Groups currently have a total of 20  
21 vacancies, of which 14 are in the Hydroelectric Development (“HD”) group. Delays in  
22 hiring staff for HD have been due to late approvals and the start-up of certain new  
23 development projects related to unregulated facilities.  
24  
25 c) No. The Niagara Plant Group, R.H. Saunders Generating Station, and the Hydroelectric  
26 Central Support Groups have not eliminated any vacant positions from our staff  
27 plan/organizational structure during the 2007 – 2009 period.  
28  
29 d) Yes, the Hydroelectric Central Support Groups are planning to fill vacancies from 2010 –  
30 2012. The Niagara Plant Group has recently been impacted by significant attrition due to  
31 retirement. As a result, it is currently reassessing its staffing strategy in an effort to  
32 achieve greater efficiencies. However, Niagara Plant Group is still expecting to fill most of  
33 its current vacancies over the 2010 – 2012 period. There are currently no vacancies at  
34 R.H. Saunders Generating Station.