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Ontario Energy Board

Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

expenditures which do not qualify for capitalization. OPG maintained that these expenditures are subject to the same project management and oversight as capital projects.

OPG benchmarks the hydroelectric business on reliability, safety and cost. OPG pointed out that the aggregate cost of the regulated hydroelectric facilities were in the top quartile for 2005 and 2006 as shown in a report by Haddon Jackson Associates.

Hydroelectric production is also subject to a Gross Revenue Charge ("GRC"), budgeted at $228.2 million for 2008 and $244.1million for 2009. The GRC is charged to hydroelectric generators under Section 92.1 of the *Electricity Act, 1988*. The GRC consists of a property tax component based on production levels and a water rental component of 9.5% on the gross revenue calculated from the annual generation.[16] OPG explained that it does not pay the water rental component on the DeCew facilities because it does not hold a water power lease for that facility, but it does pay compensation to the St. Lawrence Seaway Management Company for conveying water through the Welland Canal.

Board staff noted that the Board has used both a line item approach and an envelope approach to assessing OM&A forecasts. Board staff noted that another approach is to use benchmarking and that the Board has used proxies and utility comparisons as a basis for determining OM&A in other situations. No other intervenor made submissions regarding the hydroelectric OM&A test period forecast.

Board Findings

The Board accepts the forecast hydroelectric OM&A for the test period. The Board notes that the benchmarking results support a conclusion that the OM&A levels for the hydroelectric business are appropriate.

3.3 Capital Expenditures

OPG is seeking approval of amounts it has spent to increase capacity, as contemplated by O. Reg. 53/05, and it is seeking approval of its forecast capital budget for the test period. Table 3-2 sets out the level of capital expenditures in the test period and shows that the Niagara Tunnel Project is by far the largest capital expenditure for this

[16] The water rental component is set at 9.5% in O. Reg. 124/02.

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business. Table 3-3 shows the additions to Gross Plant in rate base over the test period.

Table 3-2: Hydroelectric Capital Expenditures

$ millions	2008	2009
Niagara Plant Group	33.6	42.2
Niagara Tunnel Project	170.6	346.8
Saunders GS	4.6	6.6
Total	208.8	395.6

Source: Ex D1-1-1, Table 1

Table 3-3: Continuity of Hydroelectric Gross Plant

$ millions	2007 Gross Plant	2008 In-service additions	2008 Gross Plant	2009 In-service additions	2009 Gross Plant
Niagara Plant Group	2,893.6	33.1	2,926.7	41.9	2,968.7
Saunders GS	1,516.5	13.1	1,529.6	6.6	1,536.2
Total	4,410.1	46.2	4,456.3	48.5	4,504.9

Source: Ex B2-3-1, Tables 1 and 2

Paragraph 6(2)4 of O. Reg. 53/05 states:

> 6 (2) 4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
>
> i.if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
>
> ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first

> order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

OPG reported two hydroelectric projects under this section of O. Reg. 53/05: the Niagara Tunnel Project and the Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project. The Niagara Tunnel Project will increase water diversion capacity at the Beck complex and is expected to increase average annual production by 1.6 TWh. The total approved budget for the project is $985 million. The capital expenditures for 2008 and 2009 are $170.6 million and $346.8 million, respectively. This project will not be completed in the test period and therefore these amounts will not be included in rate base in the test period. The Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project will convert the existing 25Hz unit to a new 60Hz unit and return G7 to service. The approved budget for the project is $32.5 million, and the capital expenditures in 2008 and 2009 are $23.4 million and $3.9 million, respectively, and are within the approved budget. This project is expected to be completed in the test period, and the amounts are included in the test period rate base.

OPG is not seeking recovery of any costs related to "financial commitments" or "pre-engineering commitment".

With respect to the balance of the capital budget (for projects not covered by 6(2)4 of O. Reg. 53/05), OPG is seeking approval of in-service additions of $46.2 million in 2008 and $48.5 million in 2009 associated with regulated hydroelectric capital projects. OPG explained the capital budgeting process as follows:

> All regulated hydroelectric projects reflected in this category of additional capital spending are identified and prioritized using a structured portfolio approach whereby engineering reviews and periodic plant condition assessments are performed to determine the short-term and long-term expenditures required to sustain or improve assets...After a project is initiated, a rigorous project management process is in place to provide project oversight...Project closure reports are produced for all projects and post-implementation reviews are conducted for all projects over $200,000.[17]

The following table summarizes the major projects for the hydroelectric business which fall outside of Section 6(2)4 of O. Reg. 53/05. The first two projects are included in the proposed test period rate base.

[17] OPG Argument in Chief, p. 45.

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Table 3-4: Major Hydroelectric Capital Projects Not subject to O. Reg. 53/05, Section 6(2)4

Project	Description	Budget *($ million)*	In-Service Date
Unit G9 Upgrade Beck	Rehabilitate unit for the first time since 1974 to prevent unit failure, overcome a 10MW de-rating and provide additional generation through improved turbine runner efficiency.	$30.0	Dec. 2009
Replace HVAC System Project at R.H. Saunders	Replace HVAC to eliminate the costs of repairing this aging system, to eliminate the use of ozone-depleting refrigerants and to eliminate health risks associated with exposure to lead and asbestos.	$11.5	May 2008
Rehabilitate Canal Lining at Niagara	Investigate and repair the walls and liners of the open cut canal that services the Beck complex to restore and maintain their integrity, prevent erosion and weathering and improve water flow.	$55.0	Dec. 2011
Unit G3 Upgrade Project at Beck	Overhaul this unit to allow for reliable production in future, prevent unit failure and to achieve increased capacity through improved turbine runner efficiency.	$31.5	Jan. 2012
Dyke Foundation Grouting Project at Beck PGS	Upgrade the protective measures to prevent recurrence of the 1958 dyke failure due to sinkholes and other phenomena on the bottom of the reservoir.	$20.0	Dec. 2010

Source: OPG Argument in Chief, page 46.

Board Findings

The Board accepts that the Niagara Tunnel and Beck G7 conversion projects are projects which come within the scope of Section 6(2)4 of O. Reg. 53/05 and notes that both projects continue to be budgeted at the level originally approved by the OPG Board of Directors. The Board will accept the inclusion of the G7 project in rate base. Any variance between the OPG Board of Directors approved forecast and actual cost will be subject to review at a future proceeding. The Board notes that the Niagara Tunnel Project is subject to continued delay and concludes that the cost for this project is uncertain at this point. However, no finding related to the cost is required because it is not forecast to enter rate base in the test period. To the extent the final costs exceed the OPG Board approved level, the recovery of those incremental costs will be the subject of a future proceeding.

The Board also accepts the balance of the capital budget for 2008 and 2009 and the rate base consequences for those projects scheduled to become in-service during the test period.

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retain all of the CMSC payments, arguing that to do otherwise would prevent it from recovering its losses associated with constrained off or constrained on situations. AMPCO submitted that OPG had failed to demonstrate that CMSC revenues are totally absorbed by the incremental costs and therefore recommended that the revenues be shared 50/50 net of incremental costs. Similarly, SEC submitted that OPG had provided no evidence to support its claim that the CMSC revenues equal the incremental unforecast costs. SEC submitted that these revenues should be treated as a revenue offset because the costs are likely included in OPG's forecasts.

OPG responded:

> CMSCs are intended to keep market participants whole, up to the operating profit they would have otherwise received, had they not been constrained-on or off by system conditions beyond their control.[24]

OPG quoted from an IESO presentation in support of this characterization. OPG maintained that if it is not able to retain the payments it will have no way to recoup the losses it would otherwise experience. OPG maintained that it would be too complex to quantify the incremental costs associated with constraint situations, but maintained that the payments, over a year, are a reasonable approximation of the impact on OPG's revenue. OPG noted that these payments are also subject to IESO review.

Board Findings

The Board will accept OPG's proposal. The losses which OPG incurs in constrained on and constrained off situations are mostly related to opportunity costs – the reduced production or less efficient production which results in lost revenues. The Board accepts OPG's evidence that the CMSC payments are designed to compensate for these losses – losses which are not otherwise incorporated into the revenue requirement. The Board will therefore not establish a deferral and variance account for this item.

3.5 Design of Payment Amount

Under the existing payment design, OPG receives $33/MWh for the first 1,900 MWh of output in any hour. Any production beyond the level of 1,900 MWh receives the market

[24] OPG Reply Argument, p. 107.

price. The objective of the incentive scheme is to provide OPG with an incentive to produce peaking supply in response to demand. The expectation is that this will benefit consumers by having a peaking resource available to improve system reliability and temper market prices through increased supply. OPG explained that this peaking capability is primarily available through the Beck complex, although there is also some capability at R.H. Saunders and DeCew.

OPG's evidence is that there have been situations when the current mechanism did not provide the right market signal to OPG because decision making is driven by the opportunity cost associated with the regulated price, rather than being driven by the market price in the off peak period. For this reason, OPG has proposed a new incentive mechanism. The formula for the proposed payment structure is as follows:

$$\sum_t [\mathbf{MWavg * RegRate + (MW(t) - MWavg) * MCP(t)}]$$

Where:

MWavg = hourly volume or the actual average hourly net energy production over the month

RegRate = the regulated rate ($/MW) for the regulated hydroelectricity facilities

MW(t) = net energy production supplied into the IESO market for each hour of the month

MCP(t) = market clearing price for each hour of the month

Under the proposed mechanism, for production greater than the threshold level OPG will receive the market price, and for production which is less than the hourly threshold OPG will notionally pay the market price for the production shortfall. The threshold will not be set at a fixed pre-determined level; the threshold will be the actual average hourly production during the month. OPG submitted that the incremental revenues associated with the proposed mechanism (revenues over the regulated payment level) will be significantly less than under the current scheme and that the proposed mechanism results in better operational drivers because decision making is driven by market signals and not the regulated rate. OPG concluded that the proposed mechanism is therefore preferred, but noted that under the mechanism OPG is exposed to greater financial risk because it must notionally purchase any production shortfall.

OPG estimated (using market simulation modelling) that the result of this production displacing more expensive generation would reduce the hourly market price by between $.40/MWh and $1.20/MWh, with annual estimated savings for consumers of between $80m and $270m. OPG submitted that in relation to the level of benefit to consumers, the incremental benefit to OPG (revenues in excess of the revenue requirement), which is estimated at between $5 million and $19 million, is reasonable. OPG submitted:

> The proposed mechanism provides the correct signals for peaking operations since it drives the decision to pump on the spread between forecast on-peak and off-peak prices.[25]

Most intervenors expressed dissatisfaction with the proposed mechanism although they supported the objective of the mechanism and generally agreed with OPG's evidence regarding the weaknesses of the current approach. VECC concluded that the proposal should be adopted but that its operation should be tracked in a deferral account for future disposition. Energy Probe and AMPCO each submitted that the proposed mechanism should be modified. SEC submitted that the current mechanism should be continued.

In Energy Probe's view, the proposed structure is flawed because the threshold is set at the end of the month and applied retroactively. This approach results in a perverse incentive to over-use the Sir Adam Beck Pump Generating Station ("PGS") because all pumping will lower the actual monthly average rate of generation at Sir Adam Beck thereby lowering the threshold for that month; this may happen when it is contrary to the interests of the grid and consumers. Energy Probe submitted that although OPG attempted to minimize the impact of this flaw, the scenario explored in the undertaking was simplified and unrealistic, and if the PGS were used throughout the month, the impact would be multiplied by 30. Energy Probe suggested that the unintended benefit could run to $4 million to $5 million per year.

AMPCO submitted that the treatment of PGS volumes resulted in double counting which should be corrected:

> ...pumping has the effect of decreasing the average monthly volume used to set the incentive mechanism threshold. Since, *ceteris paribus*, a lower threshold translates into a higher monthly average realized price for OPG than a higher threshold, the incentive for OPG to pump at the PGS is greater than indicated by

[25] OPG Reply Argument, p. 130.

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> the expected differential in market prices between peak and off-peak demand periods.[26]

OPG responded that these concerns were unfounded:

> The decision to pump is based solely on the price differential between the peak and off-peak prices at a point in time, less the associated costs. It is not based on any plan to lower the average hourly volume.[27]

OPG acknowledged that pumping will reduce the average hourly volume, but noted that the benefits to consumers from increased pumping (in terms of lower peak prices) far exceed any benefit to OPG. OPG also maintained that the concern regarding potential for gaming was baseless once elements of reality were included. For example, OPG would not be able to run the PGS continuously for physical reasons.

VECC also expressed concern that the structure of the proposal could give rise to unintended consequences including raising off-peak market prices or providing OPG a bonus even if the regulated rate exceeds the average market price for the month.

A number of intervenors took the position that the perceived flaws in the methodology could be addressed by modifying the threshold. SEC submitted that the threshold should be set exogenously:

> Because the production target that triggers the incentive is OPG's own average monthly production, OPG is being rewarded simply for exceeding its own average production on a particular day, and not for exceeding a production target that is exogenously determined to meet peak production requirements.[28]

Energy Probe proposed two alternative approaches. One would be to set the threshold externally, for example using the average hourly production for the same month in the previous three years.

OPG responded that there are two benefits to setting the threshold on the basis of actual production: it is rooted in reality and it allows for a higher volume at the regulated rate than would a predetermined volume because a predetermined volume would need

[26] AMPCO Argument, p. 49.

[27] OPG Reply Argument, p. 132.

[28] SEC Argument, p. 57.

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to incorporate a risk premium. OPG submitted that setting a higher pre-determined threshold would be inappropriate because it would drive OPG to maximize production:

> The objective is not to maximize OPG's production at the regulated hydroelectric facilities but to optimize economically efficient production based on market signals, which represent the value of production at various times.[29]

Similarly, OPG opposed setting the threshold based on average historical production. OPG argued that this alternative has the same flaw as any pre-determined threshold: "it disconnects the threshold from the actual water available to the regulated facilities."[30]

Energy Probe's other alternative would be to use OPG's proposed threshold, but to net out the effect of OPG's pumping at PGS on the threshold. Similarly, AMPCO proposed that 54MWh be added to the monthly total for every 100 MWh used for pumping. (This reflects that, on average, 46 MWh is generated for every 100 MWh of energy used for pumping.) In OPG's view, adjusting the hourly volume by adding pump energy losses (AMPCO's approach) is punitive because it is higher than what OPG has actually achieved in a given month. OPG submitted that setting an unreasonably high threshold is unwarranted given the significant consumer benefits to be achieved.

AMPCO also submitted that all SMO production should be included in the calculation of the monthly average production. Energy Probe submitted that a perverse incentive may exist in relation to the SMO and urged the Board to extend its preferred solution to the SMO activities as well. OPG responded that the SMO volumes are already included in the hourly volume (the threshold) but not in the actual net energy production (the amount compared against the threshold for settlement purposes).

Board staff questioned whether an independent evaluation or regular reporting of the impact and results might be warranted. AMPCO supported Board staff's suggestion that there be an independent review of the mechanism at the next case. OPG responded that while it supported a future review of the mechanism it would not be necessary or feasible to conduct an independent review in time for the next filing. OPG proposed to file its own review of the incentive's effects on its operating decisions as part of its next application.

[29] OPG Reply Argument, p. 131.

[30] Ibid., p. 132.

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Board Findings

The Board will accept OPG's proposed incentive mechanism. The Board finds that the structure of the proposed mechanism is an improvement on the current mechanism as it leads to decision making based on the comparison of market prices, rather than on a comparison between the market price and regulated payment.

The Board also agrees with OPG that adopting a pre-determined threshold is not a preferred approach because the objective is not to maximize production but to optimize economically efficient production based on market signals. A number of the intervenors expressed concern with the potential for gaming opportunities under the new structure, particularly as a result of the threshold being determined after the fact. The Board concludes that these concerns are overstated. The opportunities to manipulate the average hourly production for the month are effectively limited by the physical operations of the PGS and by the financial risk which OPG faces related to its decision making. The Board accepts that OPG has an incentive to base pumping decisions on the forecast spread or risk being unable to recoup pumping costs. The Board would also note that if additional pumping takes place toward the end of a month, generation will necessarily take place before further pumping is possible, and this additional generation will increase production in the associated time period thereby raising the average production.

The Board will require OPG to present a review of the mechanism at the next proceeding, as it has undertaken to do. This review will examine the impact of the incentive structure on OPG's operating decisions.

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CAPITAL BUDGET - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence provides an overview of the capital budget for OPG's regulated hydroelectric facilities for the historical years, bridge year, and the test period. It also provides period-over-period explanations and an overview of the hydroelectric project management processes.

2.0 REGULATED HYDROELECTRIC CAPITAL BUDGET

OPG's capital expenditures for the regulated hydroelectric facilities are $328.0M and $235.8M in 2011 and 2012, respectively. A summary of the regulated hydroelectric capital expenditures for 2007 - 2012 is provided in Ex. D1-T1-S1 Table 1.

OPG's investments in the regulated hydroelectric facilities reflect OPG's mandate, as set out in the Memorandum of Agreement between OPG and its shareholder, which provides as follows:

> With respect to investment in new generation capacity, OPG's priority will be hydro-electric generation capacity. OPG will seek to expand, develop and/or improve its hydro-electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible.

OPG's capitalization policy, which is provided at Ex. A2-T2-S1, is used to determine which regulated hydroelectric projects are capital projects and which projects fall within project OM&A, which is discussed in Ex. F1-T3-S3. The regulated hydroelectric capital projects discussed in this schedule, therefore, are projects that satisfy the criteria set out in the capitalization policy, namely that such projects: (a) provide future benefits beyond one year, (b) involve the purchase of a new asset or the increase in the life or output of an existing asset, and (c) meet or exceed the materiality threshold (e.g., $200k per generating unit).

OPG establishes annual budgets for the capital projects undertaken at the regulated hydroelectric facilities. As described in Ex. F1-T1-S1, section 2, the Hydroelectric Business Unit uses a structured portfolio approach to identify and prioritize projects. Projects are then administered using the project management process that is described in section 7.0 below. The hydroelectric project portfolio is approved through OPG's business planning process, which includes approval of the capital project budget (as well as the project OM&A budget) by OPG's Board of Directors ("the OPG Board"). Prior to beginning work on a project, funds are released in accordance with OPG's Organizational Authority Register through the approval of a business case summary.

Through this business planning process, the OPG Board has approved a total of $563.8M of capital project expenditures for the 2011 - 2012 test period to sustain or improve the regulated hydroelectric generating stations. Due to the multi-year nature of many of the capital projects, not all of the capital expenditures planned for the test period will necessarily come into service (and therefore into rate base) in the test period. Capital in-service additions are discussed in Ex. D1-T1-S2, section 4.

3.0 CAPITAL BUDGET SUMMARY

OPG's planned capital expenditures for the regulated hydroelectric facilities during the test period are dominated by the Niagara Tunnel project. Of the total planned capital expenditures of $563.8M in the test period, $487.0M is for the Niagara Tunnel project, with the balance of $76.7M for other capital projects at the Niagara Plant Group or the R.H. Saunders Generating Station.

The Niagara Tunnel project was originally approved by the OPG Board on July 28, 2005, with an expected in-service date of 2010. In May 2009, the OPG Board approved a revised cost estimate of $1,600M and a revised in-service date of December 2013. OPG's planned capital expenditures for the Niagara Tunnel project are $288M in 2011 and $199M in 2012. As this project will not come into service during the test period, none of its capital expenditures will be added to rate base during the test period.

With respect to the $76.7M portion of the regulated hydroelectric capital budget for the test period that is unrelated to the Niagara Tunnel project, as shown in Ex. D1-T1-S1 Table 1, approximately $61.6M ($30.7M in 2011 and $30.9M in 2012) is associated with facilities that are part of the Niagara Plant Group and $15.2M ($9.2M in 2011 and $5.9M in 2012) is associated with R.H. Saunders Generating Station.

For the Niagara Plant Group, the non-tunnel expenditures are primarily for the rehabilitation projects on units G3 and G10 at the Sir Adam Beck I Generating Station and the penstock replacement project at DeCew Falls I. Together, these four projects account for $30.9M of the $61.6M in capital expenditures planned during the test period for Niagara Plant Group facilities. The remainder consists of expenditures associated with smaller capital projects within this plant group.

For R.H. Saunders Generating Station, a significant portion of the planned expenditures are for the replacement of generator protections and control upgrades and the station service replacement project. Together, these two projects account for $9.6M of the $15.2M in test period capital expenditures for this station. The remainder consists of expenditures on a number of smaller capital projects at the station.

Descriptions and listings of the regulated hydroelectric capital projects are provided in Ex. D1-T1-S2. This exhibit also presents in-service additions for the bridge year and test period, and explains changes from OPG's EB-2007-0905 application. The remainder of this schedule provides period-over-period explanations of the capital budget, followed by a description of the project management process that OPG uses to identify, approve and oversee regulated hydroelectric projects.

4.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

<u>2012 Plan versus 2011 Plan</u>

Capital expenditures associated with the regulated hydroelectric facilities are expected to decrease from $328.0M in 2011 to $235.8M in 2012, mostly due to a reduction in the work associated with the Niagara Tunnel project. The tunnelling operation using the tunnel boring machine ("TBM") is expected to end in 2011 with an associated reduction in costs. In 2012, work is expected to continue on the installation of the tunnel lining and begin on the construction of the outlet structure.

In 2012, Niagara Plant Group capital spending (excluding the Tunnel project) is expected to increase by only $0.2M as work will be continuing on the rehabilitation of generator G3 at Sir Adam Beck I and the rehabilitation of generator G10 at Sir Adam Beck I will begin.

R.H. Saunders' 2012 capital spending is expected to decrease to $3.3M from the 2011 plan. This is a direct result of the Protections and Controls project winding down in early 2012, partially offset by: the execution phase of the excitation system replacement, the beginning of station service replacement, and the replacement of the fire water system.

2011 Plan versus 2010 Budget

Capital expenditures associated with the regulated hydroelectric facilities are expected to increase to $328.0M in 2011 from the $295.3M in 2010 mostly due to incremental work associated with the Niagara Tunnel project. While the tunnelling with the TBM continues, work will accelerate on the installation of the tunnel lining.

In 2011, Niagara Plant Group capital spending is expected to decrease by $5.5M mainly due to the completion of the DeCew Falls I penstock replacement in 2010, while the completion of the unit rehabilitation of generator G9 at Sir Adam Beck I will be offset by the beginning of rehabilitation work for generator G3 at Sir Adam Beck I.

R.H. Saunders' 2011 capital spending is expected to be $8.1M less than the 2010 budget as two large projects, the St. Lawrence Power Development Visitor Centre and the Powerhouse Crane Rehabilitation projects are completed in 2010.

5.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2010 Budget versus 2009 Actual

Regulated hydroelectric capital expenditures are expected to increase to $295.3M in 2010 from $251.0M in 2009. The main reason for the higher expenditures in 2010 is work on the Niagara Tunnel project as the rate of progress of the TBM is expected to increase, along with the ramp up of tunnel lining activities.

Capital expenditures at the Niagara Plant Group are expected to increase from $25.6M in 2009 to $36.2M in 2010. Increases are a result of planned expenditures for installation of penstocks at DeCew Falls I, station service replacement at Sir Adam Beck II and transformer replacements at the Sir Adam Beck Pump Generating Station. In addition, planned expenditures on Sir Adam Beck I G9 unit rehabilitation are higher in 2010 than in 2009 and the rehabilitation of Sir Adam Beck I G3 is expected to begin.

Capital expenditures at R.H. Saunders will be $5.4M higher in the 2010 budget than the 2009 actual costs mainly due to two projects: the Powerhouse Crane Rehabilitation, and the Generator Protections and Controls.

6.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2009 Actual versus 2009 Budget

The 2009 actual capital expenditure was $251.0M versus a 2009 budget of $395.6M, mostly due to changes associated with the Niagara Tunnel project.

Capital spending on the Niagara Tunnel project was $133.3M lower than plan in 2009 due to the contractor's slower than planned progress of the TBM, lower interest costs, and unspent contingency. The progress was slower than expected under the original contractor schedule primarily due to excess overbreak in the tunnel crown. In June 2009, following the recommendations of the Dispute Review Board ("DRB"), OPG and the contractor signed an amended design-build contract with a revised target cost and schedule. The target cost and schedule took into account the difficult rock conditions encountered, restoration of the circular cross section in areas of rock overbreak, and the concurrent tunnel excavation and liner installation work required to expedite completion of the tunnel. OPG's Board of Directors approved a revised project cost estimate of $1.6B and a revised scheduled completion date of December 2013. The advancement of the TBM was temporarily interrupted from September 11, 2009 to December 8, 2009 to repair a short section of the temporary tunnel liner that failed about 1,800 metres behind the TBM location, and to complete a planned overhaul of the TBM cutterhead, conveyor systems and other tunnel construction equipment. Installation of the lower one-third of the permanent tunnel concrete lining was ahead of schedule. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining began in September 2009.

Capital spending for the Niagara Plant Group in 2009 was $25.6M, or $16.6M below the budget of $42.2M. The significant decrease in expenditures is primarily related to changes in the Sir Adam Beck I unit rehabilitation schedule. The original schedule, which formed the basis for the last rate application, was revised because the time required to complete the necessary work exceeded the estimated outage duration. The first Frequency Conversion/Unit Rehabilitation (Unit G7) was completed on schedule and officially placed in service three months later in order to implement design changes to correct vibration problems discovered during unit commissioning. Lessons learned from the first unit rehabilitation have been applied in the planning for the subsequent rehabilitation projects. The resulting schedule changes increased 2009 expenditures for Unit G7 ($2.7M) and decreased expenditures for G9 ($9.2M), G3 ($0.5M) and G10 ($6.0M).

In addition, the G8 unit overhaul at DeCew Falls I ($0.5M) was deferred along with the Sir Adam Beck I canal lining repairs ($0.5M) and #1 elevator repairs ($5.0M). These decreases were offset by projects that were added to the capital expenditures after the last rate application. The additional capital projects include the DeCew Falls I Penstock Replacement ($3.0M), Service Center Facility ($1.5M), and the rehabilitation of the Sir Adam Beck Pump Generating Station Powerhouse Crane ($0.6M).

Capital spending at R.H. Saunders in 2009 was $11.9M which was $5.3M higher than planned. This difference was due to a variety of schedule and cash flow changes for a number of projects as follows:

- $7.2M was spent on the St. Lawrence Power Development Visitor Centre. OPG initiated community consultations in 2008 and did not include this project in its plans until the final scope had been determined and agreed to by both OPG and external stakeholders.
- $2.2M more was spent on the Protections and Controls project as the bids received were much higher than estimated.

AMPCO Interrogatory #009

Ref: Ex. D1-T1-S2, Attachment 1, Table 1

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) At page 2, the Niagara Tunnel project is described as being originally approved by the OPG Board on July 28, 2005 with an expected in-service date of June 2010. Please provide the presentation to the OPG Board that was the basis for the Board's approval of the project.

b) The Background on page 2 indicates that preparation for the new Niagara Tunnel began in 1982, that detailed engineering studies were undertaken and that an environmental assessment was approved by the Minister of the Environment in 1998. Yet on page 9 the reported progress is at a rate 27% of the planned rate. What engineering analysis was the basis of the 2005 approval and what actions have been taken against the engineers responsible for the erroneous estimate?

c) What portion of the currently estimated cost to complete the tunnel project does OPG claim is outside the jurisdiction of the OEB for the purposes of the ultimate prudence review?

d) Please confirm that some of the worst instances of overbreak with the current project have occurred where the tunnel path has intersected bore holes used to investigate the geology for tunneling purposes. Please indicate OPG's opinion as to whether the bore holes could have been protected better when decommissioned after being drilled for investigative purposes so as to protect the rock better for subsequent tunneling.

e) The Financial Sensitivity Analysis presented on page 7 of the Niagara Tunnel Project Business Case Summary (BCS) shows a Levelized Unit Energy Cost (LUEC) of 6.8 cents/kWh and an equivalent PPA of 9.5 cents/kWh. Please outline the factors that cause the difference between the two results.

f) The second table on page 9 indicates that starting March 3/2009 until its completion, the forecasted average rate of progress of the tunnel per day was to be 8.4 meters. Please confirm that over the period from March 3, 2009 until July 3, 2010 that rate of progress was approximately 7.05 m/day. Please indicate the impact of the slower rate of progress on the remainder of the project schedules and costs.

g) In calculating the cost-effectiveness of the tunnel project, OPG assumes that the costs associated with adding incremental generation capacity at Beck units, such as SAB 1 G9, ought not to be considered. Please justify this assumption.

h) In renegotiated the design/construct deal with Strabag in 2009, OPG moved from a fixed price/fixed date contract structure to a "target cost" contract. Please compare the major commercial terms of the original and renegotiated contract.

Response

a) OPG declines to respond to this question because it addresses the original project approval, which is covered by Section 6(2)4 of O. Reg. 53/05, and because the request goes well beyond "a status update" and into matters that are covered by the OEB's express determination not to review the prudence of projects that will not close to rate base in the test period.

b) OPG declines to respond to this question because it addresses the original project approval, which is covered by Section 6(2)4 of O. Reg. 53/05. In addition, the scope of this question which involves "the basis of the 2005 approval and what actions have been taken against the engineers responsible for the erroneous estimate," goes well beyond "a status update" and into matters that are covered by the OEB's express determination not to review the prudence of projects that will not close to rate base in the test period.

c) The original release amount of $985.2M is outside the jurisdiction of the OEB for the purposes of a prudence review, as per Section 6(2)4 of O. Reg. 53/05.

d) The worst overbreak did not occur where the tunnel intersected boreholes. There was significant overbreak throughout the tunnel excavation in the Queenston shale from 800 metres to 4,500 metres along the tunnel. The partial failure of the initial tunnel lining (rockbolts, wire mesh, steel ribs and shotcrete) that occurred in September 2009 at about 3,600 metres was in the vicinity of an existing borehole that remained open as a groundwater monitoring well. The original tunnel route would not have intersected this borehole, but with tunnel realignment this borehole was intersected. Based on the realignment, grouting of this borehole in advance of the tunnel excavation would likely have been beneficial and all other boreholes in close proximity to the new tunnel alignment have been sealed by grouting.

e) There are two assumptions giving rise to the differences between the $0.068/kWh Levelized Unit Energy Cost ("LUEC") and the $0.095/kWh Power Purchase Agreement ("PPA"). The first difference is that the LUEC is calculated in 2009 dollars. The tunnel analysis was updated in 2009 to reflect the higher total project cost. LUEC's are usually quoted in dollars of the current year to allow comparisons with other projects. The PPA was calculated in 2014 dollars as this would be the first full year that the tunnel would be in-service. The second difference involves the escalation. By definition, LUEC escalates

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at Consumer Price Index ("CPI") after 2009. In the case of PPA, only 20 per cent of the PPA price escalates at CPI and only after 2014.

f) From March 3, 2009 to July 3, 2010, the average Tunnel Boring Machine ("TBM") advance rate was 7.11 metres per day and included substantial excavation in the Queenston shale formation where TBM advance rates were expected to be less than the overall average of 8.4 metres per day. The 8.4 metre per day advance rate is the weighted average of different predicted advance rates in the various rock formations to be encountered along the remainder of the revised tunnel alignment. One of the lower predicted TBM advance rates was in the Queenston shale formation and higher TBM daily advance rates were predicted in most of the rock formations above the Queenston shale. TBM mining is currently only a few days behind the Target Schedule for this activity despite the interruption associated with the September 2009 partial failure of the initial tunnel lining.

g) Please see response to Interrogatory Ex. L-1-020, part c).

h) The original design build contract was for a fixed price with bonuses and liquidated damages tied to the in-service date and the flow capacity of the tunnel. The amended design build contract includes a settlement of all claims prior to its effective date with completion of the tunnel at cost and includes incentives and disincentives tied to the Target Cost, the Target Schedule and the flow capacity of the tunnel (the flow capacity term is unchanged from the original design build contract).

AMPCO Interrogatory #007

Ref: Ex. D1-T1-S1

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

OPG reports at page 5 that a section of tunnel liner failed after the renegotiation with Strabag was completed. Please indicate the cost, cost responsibility, and schedule implications of this failure.

Response

The cost of the failed initial lining remedial work is approximately $2M and is part of the actual tunnel construction cost paid by OPG. Although the remedial work delayed the tunnel boring machine mining by seven weeks, the contractor's current forecast indicates that tunnel construction will be completed by the negotiated target completion date.

contingency. The additional capacity and energy from this project will be 62 MW and 100 GWh/year, respectively.

4.1.2 R.H. Saunders Generating Station – Replace HVAC System (H-97-1864)

The project was completed under budget and on schedule in May 2008 at a cost of $11.5M. This project included the replacement of the heating, ventilating, and air conditioning system in the administration building, including the removal of asbestos insulation on the associated piping and air handler units.

4.2 In-Service Additions in 2010 Bridge Year and 2011-2012 Test Period

Summary information for capital in-service additions is provided in Ex. D1-T1-S2 Tables 4 and 5. For the bridge and test years, additional detail by project is provided on Ex. D1-T1-S2 Tables 1, 2 and 3. The largest test period in-service additions are the unit upgrades at Sir Adam Beck I, and the replacement of generator protection and controls at R.H. Saunders. These projects are described above in section 3.1. In addition, the rehabilitation of Unit G9 at Sir Adam Beck I and the construction of the new St. Lawrence Power Development Visitor Centre at R.H. Saunders are expected to come into service in 2010 and are described below.

4.2.1 Sir Adam Beck I Generating Station - Unit G9 Rehabilitation (SAB10047)

The total cost of the Sir Adam Beck I Generating Station - Unit G9 Rehabilitation project is expected to be $32.1M. This project commenced in 2008 and is projected to come into service by December 2010. The Business Case Summary is provided as Attachment 1 to this schedule. The project is currently on schedule and on budget.

This project includes the replacement of the generator, the rehabilitation of and upgrade of the turbine including installation of a new efficient turbine runner, a new liner in the Johnson valve, and a new transformer with the upgrade of associated electrical equipment. The project is expected to increase the capacity of Unit G9 by approximately 10MW.

Unit G9 was last rehabilitated in 1974 and had substantially degraded in the last five years of its operation. Very high vibration levels and unit balance issues resulted in restricting the

AMPCO Interrogatory #008

Ref: Ex. D1-T1-S2

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) Throughout the evidence with respect to the tunnel project, OPG identifies the original in-service as June 2010. On September 14, 2005 OPG issued a press release identifying the in-service date as "late 2009". Please comment on this difference.

b) In EB-2007-0905 Exhibit D1/1/1, OPG's evidence was that the non-tunnel Beck expenditures were primarily focused on the rehabilitation of generators G7, G9, and G10 at the SAB 1, with planned in-service dates of 2008, 2009, and 2010 respectively. G7 was completed in June 2009. G9 is forecast to be completed at the end of 2010 according to D1/1/2 Attachment 1 Tab 4 p. 7 and is described in D1/1/2 p. 10 as "on schedule". G10 is now scheduled to be in-service in December 2014. Please discuss the factors that are causing across-the-board schedule slippage.

Response

a) The difference is schedule contingency included in the originally approved Business Case Summary ("BCS") for risks retained by OPG as discussed on page 7 of the original Niagara Tunnel project BCS (EB-2007-0905, Ex. D1-T1-S2, Attachment A).

b) The G7, G9 and G10 upgrade program was originally planned such that the units would be available in time to take advantage of the additional water supply associated with the Niagara Tunnel project. As described in Ex. D1-T1-S1, page 6, this schedule was revised for the G7 frequency conversion because the time required to complete the necessary work exceeded the estimated outage duration. Lessons learned from this first unit rehabilitation have been applied in the planning for the subsequent rehabilitation projects. Also, given the revised tunnel in-service date, it was decided that unnecessarily compressing the unit upgrade schedules with additional engineering resources, additional construction crews as well as overlapping unit outages was not preferable from a cost or resourcing perspective.

(reference IJC website, www.ijc.org) Consultations between the Commission and the Canadian and United States governments are ongoing.

Forecast monthly flow and Lake Ontario levels derived from the Regulation Plan 1958-D model are compared with values produced by each of Environment Canada (Great Lakes – St. Lawrence Regulation Office) and NYPA, as a consistency check. When knowledge of International St. Lawrence River Board of Control plans and strategies that will result in deviations from plan is available, adjustments are applied to reflect this information. Forecast monthly flow and level values are input to the Rivmonth energy production spreadsheet application for up to the first six months of the forecast period. Thereafter, the forecast monthly flows are estimated to be consistent with flow trends predicted by the Niagara River forecast. The R.H. Saunders generating unit efficiency ratings and planned major outages are also incorporated in the Rivmonth application.

2.5 Forecast Surplus Baseload Generation Adjustment

Surplus baseload generation ("SBG") is a condition that occurs when electricity production from baseload facilities is greater than Ontario demand. During 2009, SBG was more prevalent in Ontario than it has been for many years. Increased SBG was due to reduced electricity demand resulting from depressed economic conditions and relatively moderate temperatures, as well as an increase in available electricity supply. Typically, production at Niagara is reduced during periods of SBG when water available for generation at the Beck plants may be rejected and spilled over the Falls because the generation is not required. As indicated in section 2.2, the forecast production values for Niagara are modified to account for reduced production attributable to system operational conditions, including condense-mode operations, the provision of automatic generation control and operating reserve, etc., based on an assessment of historical performance (i.e., representative of typical or normal system conditions). However, this model adjustment did not adequately account for the decreased production attributable to SBG experienced in 2009.

Significant SBG is forecast to continue through the test period based on Ontario electricity demand and generation supply forecasts. Consequently, an additional forecast SBG adjustment has been integrated into the regulated hydroelectric production forecast totals for 2010, 2011, and 2012, and itemized separately in line 21 of Ex. E1-T1-S2 Table 1. The specific SBG adjustments included in the forecast are: 0.2 TWh in 2010, 0.5 TWh in 2011, and 0.8 TWh in 2012.

3.0 OUTAGE PLANNING

Outage planning for OPG's hydroelectric generating stations is based on a streamlined reliability centered maintenance philosophy as described in Ex. A1-T4-S2.

Outages are generally planned to conduct:

- Major overhaul, rehabilitation or upgrade work
- Preventative maintenance
- Condition based maintenance
- Inspection and testing

The normal cyclical patterns of river flow within a year are considered when scheduling outages in order to minimize the spilling of water.

At the Niagara Plant Group, a consistent base maintenance program (utilizing streamlined reliability centred maintenance principles) is used except for major overhauls or upgrades. At Sir Adam Beck I, eight of the ten generating units (all at 60 cycle) are currently available for service. The two remaining units (25 cycle) were deregistered at the end of April 2009. OPG plans to undertake major rehabilitation on three of the Sir Adam Beck I units during the current business plan period. This will impact unit availability. The six pump/generating units at Sir Adam Beck Pump Generating Station were rehabilitated within the past 12 years, which has improved unit reliability. However, to maintain a reasonable level of reliability, more frequent corrective maintenance is required on these reversible pump generators than on conventional units. This is because of the complexity of the reversible pump generators compared to conventional hydroelectric turbine/generators and the increased wear and tear associated with the frequent stops and starts required for storage and peaking. Extended

HYDROELECTRIC INCENTIVE MECHANISM

1.0 PURPOSE

This evidence provides a description of the hydroelectric incentive mechanism and presents a review of how this mechanism has impacted OPG's operating decisions as required by the OEB in its EB-2007-0905 Decision.

2.0 HYDROELECTRIC INCENTIVE MECHANISM

Under the incentive mechanism approved in EB-2007-0905, OPG is financially obligated to supply a given quantity of energy ("hourly volume") in all hours and receives the regulated rate for the hourly volume in all hours regardless of the actual output from its regulated hydroelectric facilities. If OPG produces more actual energy than the hourly volume in a given hour, it receives regulated payment amounts up to the hourly volume, and market prices for the incremental amount of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated rate is reduced by the production shortfall multiplied by the market price.

The hydroelectric incentive mechanism improves OPG's operational drivers by tying operational decisions, regardless of hourly output, to market prices instead of the regulated rate.

3.0 IMPACT OF THE INCENTIVE MECHANISM ON OPERATING DECISIONS

3.1 Overview

OPG's decisions to move energy production from off-peak to on-peak periods are, within the constraints imposed by market, asset and hydrological conditions, based on economics. Specifically, these decisions are based on expectations of short run market conditions (price and demand) and the expected price spread between the off-peak and on-peak periods. The deployment of the Pump Generating Station ("PGS"), in conjunction with the Sir Adam Beck Generating Stations 1 and 2 ("SAB 1 and SAB 2"), can move substantial quantities of energy from off-peak to on-peak periods. The extent to which the PGS is used to move energy between these periods is largely dependent on the difference between on-peak and off-peak prices. While there is some peaking capability at R.H. Saunders and the DeCew Falls Generating Stations, the great majority of peaking activity occurs at the Sir Adam Beck complex.

In real time, the cost of pumping in the off-peak periods (e.g., expected market prices for electricity, incremental/decremental gross revenue charges, non-energy load charges) is continually compared with the forecast value of the additional generation in the next on-peak period(s). Similarly, during on-peak periods, the value of generation is continually compared with the net cost of re-filling the PGS reservoir during the next off-peak period(s). The associated incremental effects of PGS operations on SAB output are also included in these assessments. In both instances, if the expected value of generation exceeds the expected cost of pumping, then the PGS is bid/offered into the market to operate. This economic assessment does not incorporate any consideration of either the regulated price or the hourly volume.

The use of market signals is important to all market participants (and ultimately ratepayers) as this facilitates the movement of energy from low value periods (typically off-peak) to high value periods (typically on-peak) thus reducing overall demand-weighted market prices and hence customer costs.

OPG estimates that between December 2008 and December 2009, usage of the PGS lowered demand-weighted market prices by approximately $1.14/MWh. This value incorporates both the decrease in on-peak prices due to added generation from the PGS and the associated increase in SAB 1 and 2 output, partially offset by an increase in off-peak prices due to additional PGS load and reduced SAB 1 and 2 output. This figure is an estimate because some information - such as the offer prices of other market participants' generation - is not available to OPG and must be estimated. This reduction in market prices demonstrates the value of moving energy from off-peak to on-peak periods.

In EB-2007-0905 at Ex. I1-T1-S1, OPG estimated that the hydroelectric incentive mechanism would provide it with, on a forecast basis, approximately $12M in incremental market revenues in 2009. Between January and December 2009, OPG's actual incremental market revenues have totaled $23.2M. The difference between actual and forecast incremental revenues is attributable to:

- More energy was shifted from off-peak hours to on-peak hours than was forecast. In 2009, actual hourly production in excess of the hourly volume at Niagara (where most time shifting occurs) was 986 GWh which was approximately 25 per cent higher than the forecast of 783 GWh.
- The difference between average on-peak and average off-peak market prices (referred to as the market price spread) was higher than forecast. While actual market prices were well below expectations - the average forecast price was almost $44/MWh versus an actual of $29.5/MWh, off-peak market prices fell at a greater rate than on-peak prices resulting in higher price spreads. The actual market price spread in 2009 was $14.8/MWh; $0.7/MWh higher than forecast.

For the test period, OPG anticipates that the incentive mechanism will result in incremental revenues of $13.3M in 2011 and $16.3M in 2012, as market price spreads are expected to fall relative to 2009. It should be noted that forecasting the value associated with peaking resources, including the PGS, is subject to great uncertainty as the PGS can operate in response to significant short-run differences in hourly prices that are both difficult to forecast and not adequately described by average price spreads.

3.2 Review of Impact of Hydroelectric Incentive Mechanism on Operating Decisions

During EB-2007-0905, OPG undertook to provide a review of the incentive mechanism's effect on operating decisions. The following sections provide the results of that review.

3.2.1 Representative Metrics

To demonstrate the effectiveness of the hydroelectric incentive mechanism, OPG has chosen two measures. Because of limited peaking capability at DeCew and R.H Saunders, these measures relate only to operations at SAB/PGS. The two measures are:

- The total number of hours PGS was pumping and the total number of hours PGS was generating during the review period. This measure provides an illustration of how often the PGS is utilized.
- The daily price spreads between periods when the PGS was generating and when the PGS was pumping. The price spreads are also calculated using production volumes in both modes of operation as weighting factors to further illustrate the economic effectiveness of operating decisions.

3.3 Analysis and Discussion

3.3.1 Number of hours of PGS utilization from December 1, 2008 to December 31, 2009

The PGS was pumping for 27 per cent of the total time and was generating for 44 per cent of the total time. The PGS was not operating for 29 per cent of the total time. Based on the on/off peak price spreads, PGS is used for pumping or generating 71 per cent of the time. When PGS is not operating it is because operation is not considered economic[1]. This demonstrates that, under the incentive mechanism, the PGS appropriately operates in accordance with the financial signals provided by the forecast of on/off peak price spreads. See section 3.3.2 for a detailed discussion of price spreads.

3.3.2 Daily market price spreads during PGS generation and consumption

The column in Table 1 below titled 'Market price spread' shows, by month for the period from December 2008 to December 2009, the difference between the average market prices for the hours that the PGS was generating, and the average market prices for the hours when PGS was pumping.[2] As indicated in section 3.3.1 above, the PGS generates 44 per cent of the time and pumps 27 per cent of the time.

In order to further capture the relationship of price differential and production volume, the column in Table 1 titled 'Production-weighted price spread' shows the difference in market

[1] Sometimes PGS is utilized for operational reasons as opposed to economic reasons.

[2] On a daily basis, the market price spread is computed as the arithmetic average market price during the hours PGS was generating less the arithmetic average market price when the PGS was pumping. The monthly value is the arithmetic average of all daily values.

prices over the same hours but weighted by the generation and consumption quantities[3]. This assigns higher weighting to prices during instances of high production value, thereby providing a meaningful measure of the success of economic decisions exercised in the scheduling of the PGS. High production-weighted price spreads indicate that the actual operation of the pump storage complex occurred in proportion to the presence of stronger market signals.

Table 1
Price Spreads Between Generation And Pump Operation

Month	Market on/off peak price spread ($/MWh)	Production-weighted price spread ($/MWh)
Dec 2008	18.3	27.8
Jan 2009	15.3	26.6
Feb 2009	14.2	31.7
Mar 2009	13.1	22.0
Apr 2009	18.5	27.1
May 2009	17.6	26.7
Jun 2009	19.0	24.3
Jul 2009	11.1	15.4
Aug 2009	14.3	19.8
Sep 2009	14.5	20.4
Oct 2009	8.8	22.4
Nov 2009	15.2	21.9
Dec 2009	8.4	13.6

[3] On a daily basis, the production-weighted price spread is computed as the sum of hourly generation multiplied by the corresponding hourly market price divided by the daily generation quantity less the sum of the hourly consumption multiplied by the corresponding hourly market price divided by the daily consumption quantity. The monthly value is the arithmetic average of all daily values.

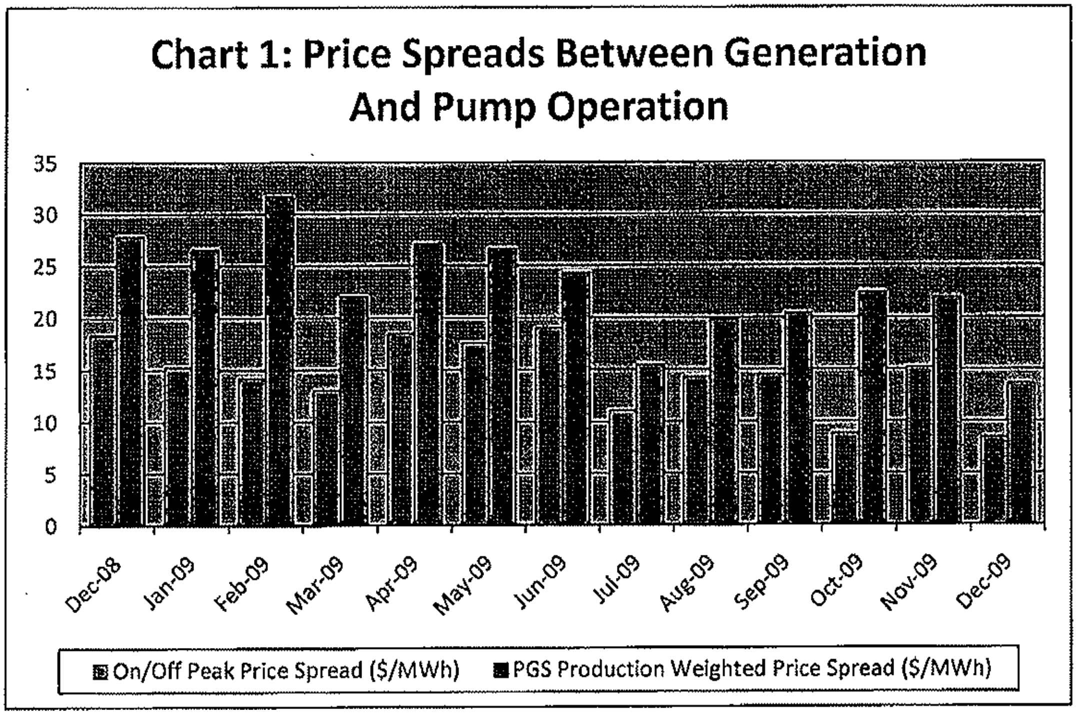

Table 1 and Chart 1 show that during the period between December 2008 and December 2009, the operation of the PGS occurred when there were positive *market price spreads*, thereby demonstrating operation in accordance with economic drivers.

Further, the notably higher *production weighted price spreads* observed throughout the review period provide additional evidence that operating decisions were made to utilize a greater number of PGS units during instances of higher price spreads. The magnitude of the difference between the market *on/off peak price spread* and the *weighted price spread* is directly related to the success associated with placing the greatest volume of PGS generation in the most appropriately priced hours. Reserving PGS generation for periods of high price is an important factor in capturing and consequently reducing the spreads between on peak and off peak prices.

3.4 Conclusions

As OPG indicated in EB-2007-0905, the new hydroelectric incentive mechanism improves the drivers for operating its peaking facilities by clearly linking decisions to market prices.

As discussed in section 3.3 above, operation of the PGS in 2009 demonstrates the value in moving energy from low- to high-value periods as shown by the decline in demand-weighted market prices. Furthermore, this benefit is realized even during periods of low demand and depressed market prices.

Finally, as discussed in EB-2007-0905, within the constraints imposed by market, asset and hydrological conditions, OPG's decisions regarding the PGS operation include an ongoing assessment of expected short run market price spreads. The measures shown in section 3.3 illustrate that the PGS operates (or does not operate) consistent with the forecast of those market price spreads.

Board Staff Interrogatory #136

Ref: Ex. E1-T2-S1, page 3, lines 1-22

Issue Number: 9.2
Issue: Is the hydroelectric incentive mechanism appropriate?

Interrogatory

The incentive mechanism generated incremental market revenues of $23.2 million in 2009, compared to a forecast of $12 million – a 93% increase. OPG expects these revenues to fall to $13.3 M in 2011 and $16.3 M in 2012 because market price spreads are expected to decline relative to 2009. Actual hourly production at Niagara was 25% higher than forecast for 2009.

a) What market price spread is OPG assuming for 2011 and 2012?

b) What are the major factors in OPG's expectations that market price spreads will decline?

c) What is OPG's forecast of total hourly production for the Niagara complex for 2011 and 2012?

d) If the actual market price spread were to equal the 2009 spread ($14.8/MWh) in 2011 and 2012, what would be the total hourly volume required to result in $12 M of annual incremental market revenues?

Response

a) OPG's forecast market price spreads in 2011 and 2012 are $10.37/MWh and $10.56/MWh, respectively. These spreads represent the average difference between on-peak and off-peak prices in each calendar year.

b) Relative to 2009, market price spreads are expected to decline primarily for two reasons:
   - A significant drop in natural gas prices relative to coal prices is anticipated over the 2011 and 2012 period. A drop in natural gas prices reduces the price difference between natural gas-fired versus coal-fired generation. Lower natural gas generation costs result in lower on-peak prices which will decrease the spread between coal-fired, off-peak prices and on-peak prices.
   - Significantly more baseload generation from the re-commissioning of Bruce Power units and the addition of wind generation.

c) OPG understands this question to be asking for OPG's forecast of the total amount of energy to be time-shifted in 2011 and 2012 since this matches the information referenced in the preamble. The forecasts of time-shifted energy for 2011 and 2012, respectively, are 1.13 TWh and 1.23 TWh.

d) OPG cannot calculate the forecast quantity of energy in excess of the monthly average required to generate incremental revenues of $12M in 2011 and 2012. OPG's forecast models are not configured to take market price spreads as a model input. These spreads are an output from the model. Reconfiguring the model to respond to this question would entail significant effort and cost.