ONTARIO POWER GENERATION

Barbara Reuber
Director

Ontario Regulatory Affairs

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May 31, 2011

RESS and VIA COURIER

Ms. Kirsten Walli
Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2011-0090 – Ontario Power Generation Inc. (OPG) Supplementary Motion Materials

Please find attached supplementary motion materials for EB-2011-0090. These supplementary materials are additional background materials that may be referenced in argument.

Pursuant to Procedural Order # 1, I am providing two (2) hardcopies and one electronic copy in searchable PDF format filed through the OEB's web portal (RESS).

Yours truly,

Barbara Reuber

Attach:

c. Charles Keizer Torys
Crawford Smith Torys
Carlton Mathias OPG
EB-2011-0090 Intervenors (via email)

EB-2011-0090

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule. B;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities;

AND IN THE MATTER OF a motion by Ontario Power Generation Inc. pursuant to Rule 42 of the Ontario Energy Board's *Rules of Practice and Procedure* for an Order or Orders to vary the Decision with Reasons EB-2010-0008 dated March 10, 2011.

Supplementary Motion Materials

Torys LLP
Suite 3000, 79 Wellington St. W.
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Toronto, ON M5K 1N2

Mr. Charles Keizer & Mr. Crawford Smith
Co-Counsel for the Applicant,
Ontario Power Generation Inc.

TABLE OF CONTENTS

TAB 1

Key Planning Assumptions - Financial

- **Regulated Revenues**
  - Regulated revenues for 2009-2010 reflect current rates as approved by the OEB, as well as amounts related to the treatment of tax loss carry forwards.
  - Regulated revenues for 2011-2012 and 2013-2014 reflect assumed recovery of costs and return on equity through two-year rate terms, consistent with the current regulatory framework. Regulated revenues incorporate ROE of 8.39% and deemed capital structure of 53% debt / 47% equity, and riders for approved deferral accounts.
- [redacted]
- **Pension and OPEB Expense**
  - 2009 year-end value of pension fund assets is assumed to be equal to its value as of August 31, 2009.
  - Pension fund investments are assumed to earn 7% annually in subsequent years, compared to 6.5% used in BP 2009-2013.
  - Discount rates used for valuing pension and OPEB liabilities assumed to be 6.8% and 7% respectively.
  - Actual discount rates for 2010 expense will be established based on December 31, 2009 closing market rates.
- **Depreciation Lives**
  - Darlington service life will be extended to 2051 consistent with planned refurbishment.
  - No other significant changes to nuclear or hydroelectric service lives.
- **Other**
  - After experiencing a strong recovery during 2009 which partially recovered 2008's losses, OPG's nuclear funds are assumed to earn 5.15% annually over the plan period.
  - Regulated rates and financial statements prepared on Canadian GAAP basis for all years; an updated plan reflecting IFRS implementation effective 2011 will be finalized in December.
  - [redacted]

CONFIDENTIAL

ONTARIO POWER GENERATION

TAB 2

August 18, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2601
Toronto, Ontario
M4P 1E4

Attention: Mr. Paul B. Pudge, Board Secretary

Re: RP-2003-0063 – Union Gas Limited Blue Page Update

Dear Mr. Pudge:

Please find enclosed Union's Blue Page Updated evidence.

Union filed its Phase I evidence in the above proceeding on May 23, 2003. This evidence was based on Union's annual forecasting process. This process is initiated each summer with the development of a new demand forecast and gas supply plan which are then used as the basis for budgets (developed in the fall) which apply to the upcoming year. As a result the Phase I evidence filed was based on a forecast that reflected information available in the summer of 2002. The use of more recent information including 2002 year-end actuals was not possible if Union was to construct all the supporting evidence and schedules to file and to minimize the amount of retro-active adjustment necessary as a result of implementing rates after January 1, 2004.

Therefore, immediately after filing its Phase I evidence, Union began the forecast process for this year with the intent of providing an evidence update for this proceeding that reflected more current information. This update was completed at the same time as responses to interrogatories were received. While administrative constraints precluded Union from printing and distributing this update simultaneously with the responses to interrogatories, where an interrogatory response was impacted by the evidence update, Union responded giving both the response reflecting the original evidence and the blue page evidence.

Also enclosed are the following:

Exhibit A, Tab 16, Page 1 of 2, Corrected
Exhibit List for B Binder (file at the front of your binder)
Exhibit B1, Tab 3, Appendix A, Page 4 of 4, Corrected
Exhibit B1, Tab 4, Page 2 of 7, Corrected
Exhibit C1, Tab 5, Addendum
Exhibit C5, Tab 2, Schedule 6, Corrected
Exhibit D1, Tab 4, Appendix C, Page 4 of 9, Corrected
Exhibit E1, Tab 1, Page 4 of 5, Corrected
Exhibit F5, Tab 4, Schedule 1, Corrected
Exhibit G1, Tab 1, Page 3 of 16, Corrected
Exhibit G1, Tab 1, Page 12 of 16, Corrected
Exhibit H3, Tab 10, Schedule 1, Corrected

If you have any questions concerning this correspondence or the enclosed Application please call me at (519) 436-4515 or Bryan Goulden at (519) 436-4637.

Yours truly,

Marcel Reghelini
Director, Regulatory Affairs

Enclosures

cc: Michael Penny, Torys
RP-2003-0063 Registered Intervenors

TAB 3

POST RETIREMENT BENEFITS

Union's post retirement benefits decreased to $5.4 million from a previously estimated $5.8 million. The main reason for this decline is that Union is revising its post retirement benefits plan to reduce the benefits provided to new retirees.

Table 2 – Comparison of Post Retirement Costs for 2004 Test Year

($ Millions)	Original Filing	Blue Page Update	Variance
Post Retirement Benefits costs	$5.8	$5.4	($0.4)

PENSION

Union's pension costs have increased to $21.4 million from $19.0 million previously estimated. The Defined Benefit pension costs have increased by $3.3 million due to revised assumptions from Towers Perrin (Union's actuary). These assumptions account for a lower discount rate and lower expected rate of return on the plans assets.

Table 3 – Comparison of Pension Costs for 2004 Test Year

($ Millions)	Original Filing	Blue Page Update	Variance
Defined Benefit Pension costs	$15.8	$19.1	$3.3
Defined Contribution Pension costs	3.2	2.3	(0.9)
Total	$19.0	$21.4	$2.4

TAB 4

RP-2003-0063 1

EB-2003-0087

EB-2003-0097

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004. 3

BEFORE: 4

Paul B. Sommerville 5
Presiding Member

Art Birchenough 6
Member

DECISION WITH REASONS 7

March 18, 2004 8

supported as part of the revenue requirement. It would be perilous to create a situation in which the gas distribution utility, alone among business categories, could not effectively attract and keep quality employees through the offering of reasonable incentive programs.

537
The Board therefore approves the request for the incentive component of total compensation and makes no additional adjustments to salaries and wages as a result of its consideration of this item.

538
Benefits

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Where benefit costs are concerned, the Board accepts the evidence presented by Union, supported by Towers Perrin, that benefit costs per FTE have risen by approximately 28% since 1999, due mainly to health cost increases. This evidence was not credibly challenged. The Board also notes that the total number of FTE's over the same period has declined by approximately 400. Accordingly, the Board finds that the net impact of the above variables results in an increase of $2.2 million in benefit cost over this period and accepts that the projected 2004 benefit cost of $25.5 million is reasonable.

540
Post Retirement Benefits

541
The Board also accepts the evidence presented by Union, supported by Towers Perrin, that the cost of post retirement benefits has increased in the period from EBRO 499 to 2004, due mainly to changes in accounting rules and discount rate assumptions. Therefore, the Board finds the request of $5.4 million in the 2004 revenue requirement to be reasonable under present circumstances.

542
Pensions

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Where Pension costs are concerned, the Board accepts that these costs have increased for the company as a result of negative returns on pension fund assets due to a decline in equity markets and also due to increased pension obligations as a result of a declining trend in long term bond yields.

544
The Board notes the concerns of intervenors regarding the negative returns on pension fund assets, but also notes that the Board has been provided with no evidence to support the position that the achieved level of performance was due to imprudent actions by the Company. The Board also finds that increased obligations due to a declining trend in long term bond yields are beyond the immediate control of the Company. The Board therefore approves the pension cost component of the employee compensation package.

TAB 5

8

impact is approximately $91.6 M[220] for the two test periods. Whatever the actual difference turns out to be as at December 31, 2010 and 2011, the revenue deficiency should be adjusted for the income tax PILs impact. However, if OPG's request to place the revenue deficiency in a variance account is approved, it will defer compensation costs and income tax impacts for the test period 2011-2012 into the future period 2013-2014. Staff submits that there is no reason in this case why a known cost should not be recoverable now as opposed to deferring to a future period.

9.4.3 Cash versus Accounting Based Forecasts

Having argued that deferring portions of the pension and OPEB costs is not appropriate, staff will argue below that the total forecast that should be included in the test year payment amounts should be on a cash basis.

The following table of pension and OPEB costs was compiled by Board staff from OPG's evidence.

[220] Exh.F4/Tab2/Sch.1/Table5/ln31 Income tax rates: for 2011, 26.5%; for 2012, 25.0%. (26.5%+25.0%)/2=25.75% $264.2 M*25.75%/(1-.2575)= $91.6 M

TAB 6

expecting this Board to accept) for the Test Period.

0.2.6 ***Rate Base.*** We have agreed with Board Staff with respect to reductions to nuclear rate base of $128 million in 2011 and $161 million in 2012.

0.2.7 On the other hand, we support the inclusion in rate base of the St. Lawrence Development Visitor Centre.

0.2.8 ***Operating Costs and Benchmarking.*** OM&A should be reduced, primarily on the nuclear side. We have approached this from two main metrics: benchmarking of Darlington non-fuel costs, and reductions in overall compensation costs to reflect a stepwise move toward the 50th percentile. We have also proposed, or agreed with others, on a number of smaller adjustments.

0.2.9 The Applicant's considerable benchmarking activity since the Original Decision has produced tangible results, and they should be applauded for embracing this exercise with some vigour. There are, however, still significant steps to take, and we propose a number of those steps in these submissions.

0.2.10 ***Darlington Refurbishment.*** We believe that the CWIP in rate base proposal should be denied, but that the Test Period OM&A for the Darlington refurbishment should be approved. We have also proposed that the amount of $245.6 million of credit adjustments to nuclear liability and other accounting entries, net of the tax impacts of those adjustments, should not be implemented by this Board. The result is an increase in revenue requirement of $195.3 million.

0.2.11 Our proposal to increase revenue requirement goes in tandem with a proposal that the Board accept the capital spending on the Darlington refurbishment in the Test Period, but with warnings and conditions designed to ensure that, before the project becomes a fait accompli, it is thoroughly reviewed.

0.2.12 ***Pension/OPEB.*** With respect to pension and OPEB costs, we do not agree that the Applicant should defer recovery of all of the $264.3 million of expected increases until a subsequent rate application. Instead, and recognizing that these costs can be volatile, we agree with Board Staff that they should be recovered on a current basis in the Test Period, but that they should be recovered using the cash basis used by other regulated utilities. The cash costs associated with pension and OPEB are significantly more stable, yet still recover the same total cost over time.

0.2.13 ***Tax Provision in Rates***. Flowing from the analysis of the Tax Loss Variance Account (below), we conclude that the 2011/12 Test Period tax provisions of $58.0 million for hydroelectric, and $129.8 million for nuclear, and associated gross ups, should in fact be zero. This reduces revenue requirement over the Test Period by $262.6 million.

TAB 7

238. The fact that OPG, in an Impact Statement, now forecasts a $262M difference between the forecast of pension and OPEB costs included in the application and its updated projection of such costs should not prompt the Board to grant the variance account protection OPG requests. In this connection, we agree with and support the submissions of Board Staff and others to the effect that the increased amount that OPG is now anticipating for the test period be calculated on the more stable cash basis to which Board Staff refers in its submissions, and included in the 2011/2012 revenue requirement amounts. The request for a variance account in which to record these costs should be rejected.

XIV. COSTS

239. CME requests an award of its reasonably incurred costs of participating in this proceeding.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 6TH DAY OF DECEMBER, 2010.

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Counsel for CME

TAB 8

PUBLIC INTEREST ADVOCACY CENTRE
LE CENTRE POUR LA DEFENSE DE L'INTERET PUBLIC
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Michael Buonaguro
Counsel for VECC
(416) 767-1666

December 6, 2010

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
EB-2010-0008: Ontario Power Generation Inc. – Payment Amounts

Please find enclosed the submissions of VECC in the above noted proceeding.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

10.2 Are the balances for recovery in each of the deferral and variance accounts appropriate?

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

10.6 What other deferral and variance accounts, if any, should be established for the test period?

DRP Deferral Account

126. As noted earlier a Darlington Refurbishment Project Deferral Account should be established to track expenses related to the DRP in the test period that could be the subject of disallowance in the event the DRP is not approved.

Surplus Baseload Generation Deferral Account

127. As discussed earlier VECC supports the Board Staff proposal that SBG be tracked in a deferral account rather than forecast and embedded in rates.

Pension/OPEB Variance Account

128. VECC has reviewed and concurs with Board Staff's analysis with respect to the request for a Pension/OPEB Variance account and the reasons why the Board should reject the request.

129. In particular VECC notes that historically the precedent relied upon by OPG, the existence of a similar account to the benefit of Hydro One Networks Inc. ("HONI"), was established under very specific and unique circumstances.

130. HONI Distribution applied for and received Board approval for a deferral account for its pension costs in RP-2004-0180/EB-2004-0270, an application that was granted by the Board by a decision dated July 14, 2004. The decision noted that the Board dispensed with a hearing and notice of the proceeding on the basis that no party would be materially affected by the issuance of the requested accounting order.[65] Furthermore the Board noted, in denying the actual recovery of the deferred pension costs at that time, that:

> The Board is currently undertaking a process to establish approved rates for electricity distributors, based on updated revenue requirements, with the intent that these new distribution rates will be effective on May 1, 2006. Post-retirement benefits and pensions is one issue that will be under consideration as part of this process,

[65] RP-2004-0180/EB-2004-0270 decision dated July 14, 2004, page 2.

TAB 9

EB-2010-0008

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c. 15 (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders determining payment amounts for the output of certain of its generating facilities.

Written Argument Of The Consumers Council of Canada

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Robert B. Warren
(416) 365-1110
(416) 365-1876 (FAX)
Counsel to the Consumers Council of Canada

forecast and outside of the control of OPG. In effect, they are a pass-through. The Council supports the suggestion by Board Staff that OPG will be required to demonstrate that it has made efforts to reduce its energy consumption prior to clearing the account.

152. With respect to OPG's proposal for a Pension and OPEB Variance Account the Council supports the analysis and position advanced by Board Staff that the establishment of the account is not warranted at this time with the amounts calculated on a cash basis and not on the accounting basis proposed by OPG.

METHODOLOGY FOR SETTING PAYMENT AMOUNTS (Issue 12)

153. The Board in the last payments proceeding expressed an interest in whether the payment amounts could be determined through some form of incentive regulation mechanism going forward. When determining the Issues List for this proceeding the Board narrowed the scope of the issue to a consideration of what steps might be appropriate to establish a framework for incentive regulation or other form of alternative regulation that would be applied in a future test period.

154. OPG has proposed that, following a decision in this proceeding, it would file an application setting out its proposal for incentive regulation. A hearing process would be initiated including the introduction of expert evidence. Under OPG's proposal, the Board would determine the form of incentive regulation to be applied to OPG and OPG would file a base year, cost of service application for the post 2010 period. (**AIC, p. 99**)

155. Board Staff commented on OPG's approach in its submissions characterizing it as "aggressive and in all probability unrealistic." (**Board Staff Submissions, p. 107**) In addition, Board Staff pointed to the fact that determining an IRM rate adjustment plan for OPG prescribed assets would be complicated relative to the development of a plan for transmission or distribution utilities. Board Staff pointed to the complexity associated with OPG's nuclear asset retirement obligation, the absence of a total factor productivity study, and the lack of any precedents. In addition, Board Staff raised the issue as to whether there should be a technology specific IRM plan for each of OPG business units. **Board Staff Submissions, pp. 107-108**)

TAB 10

approved rates only for the 2008 test year in that decision. In 2009, THESL was required to file an application in March to update its 2009 revenue requirement and distribution rates to reflect the updated cost of capital parameters. The Board considered the application in an expedited proceeding and rendered its decision following a one-day oral hearing on April 3, 2009.[13]

More recently, the Board approved a two-year Cost of Service application for Hydro One Networks distribution for the 2010 and 2011 test years. And, similar to the decision for THESL, the Board approved the rates for the 2010 test year, and directed Hydro One Networks to file a revenue requirement update for 2011 distribution rates.[14] The Hydro One Networks case was discussed at the oral hearing for this application on October 28, 2010.[15] Hydro One Networks filed the application to update the revenue requirement and distribution rates for 2011 on November 29, 2010. While this matter is before the Board the application is intended to be formulaic in nature and will likely be processed in an expedited manner.

The Board's policy and practice in this regard is to ensure that the rates approved in the test year reflect current information on the cost of capital and macroeconomic conditions. While it is possible to get forecasts that are further out than one year, the margin of error of extended forecasts increases, reflecting imprecision in the relationships between drivers of the forecasts and the fact that conditions can change over time. The increased "forecasting error" inherent in forecasts extending further forward in time limits their informational utility. *Consensus Forecasts* restricts its normal forecasts to three months and 12 months out to increase the informational value of the forecasts by ensuring that forecasting error is not too large. The calculation of the ROE for a test year period of one year adopts this philosophy to ensure that the prospective test year ROE has reasonable precision.

In cross examination on October 28, 2010, the OPG witness acknowledged that the further out one forecasts, the less precise the estimate is. The witness indicated that OPG would be willing to apply for an update for 2012, and also suggested that a deferral or variance account could be established, whichever the Board found most

[13] EB-2009-0069, April 3, 2009,Tr. p128/ln28 to p134/ln11

[14] ExhK12.2, p2-3 (Excerpt from p50-51 of the EB-2009-0096 Board Decision, April 9, 2010)

[15] Tr. Vol. 12, p101-102

expedient.[16]

Board staff submits that a deferral or variance account to deal with differences in the cost of capital "forecasts" is not warranted; such an approach ascribes precision to the Cost of Capital estimates that is not supportable.

While there would be a cost to a subsequent regulatory proceeding to set 2012 payment amounts based on updated cost of capital parameters established based on data for the month of September 2011[17], such an approach would result in more precise estimates that the Board and all parties could have greater confidence in. This is the reasoning that the Board has adopted in the previous 2-year cost of service applications for THESL and Hydro One Networks.

While the Board in the previous payments case did accept a two-year test period for OPG, the ROE was set based solely on expert evidence. Also, the ROE was set in the Board's decision on November 8, 2008, which was significantly along in the test period from April 1, 2008 to December 31, 2009, and when the ROE of 8.65% could be assessed against actuals and forecasts covering most of the previous test period. These circumstances do not prevail in the current application. The Board has subsequently reviewed the cost of capital applicable to all Ontario energy sectors that it regulates and established updated guidelines in the Cost of Capital Report; these guidelines are applicable to OPG's prescribed assets.

Therefore, Board staff submits that prescribed payment amounts for the 2011 test year only (i.e. March 1 to December 31, 2011) should be approved at this time. Prior to the 2012 test year, OPG should file an update for the 2012 revenue requirement and prescribed payments based on updated cost of capital parameters. This would be a formulaic update of the cost of capital parameters, and associated taxes/PILs, while operating expenses and rate base would be held constant at the 2012 levels approved by the Board in this decision, and could be dealt with in an expedited manner. Having

[16] Ibid., p98

[17] Per the methodology in the Cost of Capital Report, cost of capital parameters are calculated based on data from the Bank of Canada, Consensus Forecasts and Bloomberg LLP three months in advance of the effective date for the rates. For OPG's prescribed payments effective March 1, 2011, data from November 2010 will be used. For the 2012 test year covering January 1 to December 31, 2012, the updated parameters will use data from September 2011 – three months in advance of January 1, 2012.

TAB 11

to be long term debt, but is not actually represented by real long term debt, the Applicant has proposed that the rate used should be the Board's deemed rate, which was at the time of the Application 5.87%. Board Staff has noted that this proposal is inconsistent with Board decisions, and is based on a clearly incorrect interpretation of the Board's 2009 Cost of Capital Report, but Staff then goes on to suggest that, since the new deemed rate of 5.48% is lower than, and close to, the actual debt cost, "the Board may wish to consider accepting OPG's proposal in this Application" [Staff, p. 8].

3.2.3 With respect, we strongly disagree. The Board has an established interpretation and practice relating to notional long term debt. If the Board in this case allows the Applicant's proposal, the Board will then have two established interpretations and practices, and will in effect be inviting utilities to select the approach that gives them the highest revenues in any given year. This is clearly inappropriate. The Board's deemed rate is intended to be available where there is no other evidence of the utility's cost of long term debt. In this case, there is ample evidence of OPG's long term debt rate, and a deemed rate adds nothing.

3.2.4 In our view, when the Board has sufficient evidence before it on an issue, it is proper to follow that evidence in reaching its decision. It is not proper to fall back on a default value or deemed amount in the face of direct evidence on the point.

3.2.5 Therefore, it is submitted that the weighted average long term debt rate for OPG's actual long term debt should be applied to the entire amount of LTD capital required under the approved capital structure.

3.2.6 ***Short Term Debt Update***. The Applicant has proposed short term debt rates for both 2011 and 2012, based on December 2009 forecasts from Global Insights. The use of this dated information results in substantial increases in the cost of short term debt from 2011 to 2012.

3.2.7 In principle, we believe that the short term debt rate, like the long term debt rate, should be based on the best evidence currently available. In this case, using a year old forecast, particularly when it is being applied to two forward years, is inappropriate. Instead, it is submitted that the forecast of short term debt costs should be updated using December 2010 forecasts. We would anticipate that this will result in a material reduction in the cost of short term debt for the Test Period.

3.3 ***Different Capital Structures/ROE for Hydroelectric and Nuclear***

3.3.1 The Applicant has proposed to continue the approach, approved in the Original Decision, of using the same capital structure and same ROE for both the hydroelectric and nuclear assets. They have presented the evidence of Ms. McShane in support of that approach. GEC presented the evidence of Mr. Chernick, and Pollution Probe