May 13, 2009

Mr. Raymond Gorman, Q.C., Chairman
New Brunswick Energy and Utilities Board
Province of New Brunswick
15 Market Square, Suite 1400
Saint John, NB
E2L 4Y9

Dear Mr. Gorman,

Enclosed is the report on our review of certain evidence filed by NB Power Distribution and Customer Service Corporation ("DISCO") with the New Brunswick Energy and Utilities Board in support of your investigation into their 3% rate increase as ordered by the Minister of Energy.

Our report is prepared in accordance with the terms and conditions outlined in your letter of March 24, 2009 and encompasses a review of DISCO's forecasted purchased power expense and the PDVSA Settlement Deferral Account for the fiscal year ended March 31, 2010.

If you have any questions, please feel free to contact me at your convenience.

Yours truly,

Andrew P. Logan, C.A.
Partner

Encl.

REVIEW OF EVIDENCE

in connection with the New Brunswick Energy and Utilities Board's investigation into a 3% rate increase effective April 1, 2009 by

NB Power Distribution and Customer Service Corporation

Andrew P. Logan, CA
Partner

May 13, 2009

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INTRODUCTION

The 2009/10 NB Power Group budget was passed by the Board of Directors on December 12, 2008. Included in this budget was a 3% increase in the rates and tolls for the NB Power Distribution and Customer Service Corporation ("DISCO"). On February 4, 2009, the DISCO Board of Directors approved the 3% increase across all customer classes effective April 1, 2009. According to the Electricity Act, DISCO may change its rates and tolls without application to the New Brunswick Energy and Utilities Board ("Board") if the amount does not exceed the limits set out in section 99, which states:

> *"The Distribution Corporation may change the charges, rates and tolls charged by it for any category of service if the change in the charges, rates and tolls does not exceed the greater of*
>
> *(a) 3%*
>
> *(b) The percentage change in the average consumer price index"*

The Minister of Energy subsequently notified the Board that they were to make an investigation pursuant to Section 24(1) of the Energy and Utilities Board Act, which states:

> "*The Minister may direct the Board to make an investigation and report to the Minister upon any matter over which the Board has jurisdiction*."

The Minister further instructed the Board to make an investigation into the necessity for the 3% increase in the charges, rates and tolls of DISCO to be effective April 1, 2009.

On March 31, 2009, the Board issued an order to DISCO indicating their intention to conduct the requested investigation and outlined the process generally as follows:

- DISCO was to make available by April 30, 2009 a complete package of evidence relating to its forecasted revenues and costs for 2009/10;

- Written questions from registered participants are to be submitted by May 8, 2009;
- DISCO is to respond to the interrogatories by May 19, 2009; and
- A public hearing is to be held commencing on May 27, 2009.

SCOPE OF ASSIGNMENT

We have been requested by the Board to review certain parts of the evidence filed in support of the increase. Appendix I to this report outlines the specific procedures contained in the Board's Terms and Conditions Retainer letter of March 24, 2009.

Due to the relatively short time frame to conduct the investigation, our assignment began before the final evidence was made public. The preliminary draft evidence we initially began with was cross referenced to the final information package. No exceptions were noted with the documentation filed by DISCO on April 30, 2009.

The criteria for review engagements performed by Chartered Accountants can be found in the Canadian Institute of Chartered Accountants Assurance Handbook. Section 8100.19 describes review procedures as follows:

> A review consists primarily of:
>
> (a) making enquiries concerning financial, operating, contractual and other information, and considering responses that, in addition to oral responses, may take the form of listings, schedules or other documents; and
>
> (b) applying analytical procedures such as comparing the current and prior period information and considering the reasonableness of financial and other inter-relationships. Analytical procedures performed during a review engagement would normally be less extensive than analytical procedures performed during an audit. Explanations for relationships

and individual items that appear to be unusual would be obtained by directing enquiries to appropriate personnel of the enterprise, the responses to which the public accountant is entitled to accept without examination of supporting evidence as long as such responses appear plausible;

(c) having discussions with appropriate officials of the enterprise concerning information received and the information being reported on.

While the evidence reviewed was not completely financial in nature, the guidance found in the CICA Handbook does provide a reference as to the nature and type of review procedures used to reach our conclusions. It is important to note that review procedures are not intended to provide audit level assurance and consequently we are not expressing an audit opinion on any of the information covered in this report.

A significant portion of the evidence and supporting documentation reviewed during our engagement was confidential in nature. Consequently, undertakings were executed by the engagement team in accordance with the Board's terms and conditions regarding confidential information. These undertakings were reviewed and agreed to by NB Power.

Forecasted Fuel and Purchased Power Expense

Background

Unlike the consolidated group documentation submitted by NB Power in support of last year's increase, the information for the current year's investigation included only the forecasted revenue and costs for DISCO. The information package submitted on April 30, 2009 contained the familiar format used by DISCO over the last few years for its rate applications in 2006 and 2007, and for the 2008 investigation. The forecast for purchased power expense can be found in section 2 beginning on page 22. We have summarized the forecast in a slightly different format to facilitate organization of this report (see Appendix II). Total purchased power expense for the fiscal year ended March 31, 2010 is forecasted at $1,194.7 million, representing an increase of 22.45% from the expected cost for 2008/09. DISCO's forecasted energy requirements (and resulting costs) for 2009/10 are supplied from three primary sources:

Source	Percentage of Total Expense[1]	Percentage of Budgeted Load Provided
NB Power Generation Corporation ("GENCO")	77.8%	67.6%
NB Power Nuclear Corporation ("NuclearCo")	20.8%	28.6%
Renewable and other energy sources	3.3%	3.8%

The forecast is further impacted by two deferral accounts – the PDVSA Settlement Deferral Account and the Point Lepreau Generation Station ("PLGS") Refurbishment Deferral Account.

Our report and results of our procedures are segmented by source and follow accordingly.

[1] Column adds to >100% as PDVSA settlement credit and PLGS Deferral amortization expense not included.

Purchased Power Expense – GENCO

Power purchased by DISCO from GENCO is governed by an agreement referred to as the Vesting Power Purchase Agreement ("PPA"). The Vesting PPA outlines the pricing mechanisms and contains two main components:

- Vesting energy charge comprised of a fuel component and a contribution to fixed costs; and
- Capacity payment which covers the capital costs associated with the generating assets.

Other less significant components include capacity payment adjustments, interruptible and surplus energy charges, ancillary service credits and export benefit credits (also known as the third party gross margin credit).

Two amendments to the Vesting PPA were approved by the Boards of DISCO and GENCO in April 2009. The amendments included changes to the following areas:

- Third party gross margin credit forecast will now be calculated on an annual basis (as opposed to a five year basis in the original agreement) and the 20% banding has been eliminated;
- Clarification on the inclusion of PLGS costs in the DISCO deferral account and key assumptions used in setting the vesting energy price during the refurbishment period;
- Other modelling guidelines used to set the Vesting Energy Price were clarified; and
- The fuel component of the vesting energy price will be set annually prior to the commencement of the fiscal year (previously set on October 1 prior to the start of the fiscal year).

The forecast prepared for 2009/10 included the revisions contemplated in these amendments. We reviewed signed copies of the amendments and ensured that the changes as described were properly included in the forecast calculations.

Calculation of the Vesting Energy Charge

The vesting energy charge is comprised of a fuel component and a payment towards fixed costs. The fuel component charge is calculated by multiplying the vesting energy requirement with the vesting energy price ("VEP"). For 2009/10, the forecast includes 9,372,300 MWh of energy to be supplied from GENCO's heritage assets at an average price of $57.71 for a total fuel component charge of $540.9 million. The VEP is determined through a simulation process using specialized software and is discussed below.

For the 2009/10 forecast, the simulation was a combination of two runs as specified in the amendments to the Vesting PPA[2]. The results determined by the first run considered production from PLGS at a capacity factor of 71.78% up to the planned restart date of October 1, 2009. These results produced the baseline needed to determine the incremental costs for GENCO to provide replacement power to DISCO while PLGS was under refurbishment. The balance of the year was modeled using PLGS at a capacity factor of 94.9% (reflecting the efficiencies gained from the refurbishment). This resulted in two VEP's for the forecast year. For the first 6 months, the VEP was $42.82/MWh and for the balance $69.19/MWh giving a weighted average of $57.71/MWh. The large difference in the two prices reflects the additional expense as higher cost generating units come on-line to supply energy for the winter load demand.

[2] See DISCO information package, April 30, 2009, Appendix B, Amendment No.3, Section 9.9 (describing new section 6.15 to the Vesting PPA)

Vesting Energy Charge – Fuel Component

Review of ProMod™ Modeling Assumption Data

(Scope of Work Reference 1 (i) a & b)

NB Power uses an industry standard production modeling software known as ProMod™ to simulate the operation of their electricity system and to facilitate resource planning, fuel budgeting, and to forecast export sales, among other uses. Our review commenced with a brief overview of the ProMod™ system conducted by NB Power employees. The format and layout of the information was consistent with that of the prior year and was roughly organized around the following outline:

- Load forecast including total requirement, wind generation forecast and non-utility generator forecast;
- Foreign currency hedge settlement gains and losses forecast;
- CPI (Inflation) assumption and support;
- Annual maintenance and refurbishment outages and other operational constraints;
- Hydro energy production forecast;
- Price and consumption forecasts for fuel including details on:
  - Heavy fuel oil
  - Light fuel oil
  - Petroleum coke
  - Coal (Import and local)
  - Production consumables (e.g. – limestone)
  - Nuclear fuel components
- Commodity hedge settlement gains and losses forecast; and
- Assumptions for external purchases including price and interconnection purchase forecasts.

The supporting information is then collated into a one-page input summary that outlines the key variables for the ProMod^{TM} run with comparative figures for the prior year.

The pricing forecasts are a key component of the overall model and consequently a significant portion of the information is devoted to this area. We reviewed the fuel price forecasts for each generation facility with NB Power staff including any additional components that form the total cost (e.g. – freight, limestone, gypsum removal). We were provided further detail on the pricing calculations for the non-utility generators (NUG's) including a review of each contract and the methodologies used to determine the cost of energy from the NUG's.

Other components of the forecast that were reviewed in detail included:

- Load forecast data and assumptions on transmission losses;
- Hedge settlements (both foreign currency and fuels);
- Maintenance outage plans (including the PLGS Refurbishment);
- Interconnection purchases; and
- Foreign Currency and CPI Forecasts;

The ProMod^{TM} results were reviewed in detail and included the following reports for each of the modelling runs:

1. Source of Supply for the vesting contract load expressed in GWh by generating facility/fuel type;
2. Vesting contract fuel costs expressed in dollars by fuel type/generating facility;
3. Vesting contract fuel auxiliary costs expressed in dollars by cost/generating facility;
4. Other purchased power costs including interconnection purchases, DISCO NUG's, GENCO NUG's and renewable energy;

5. Vesting contract fuel and auxiliary consumption expressed by fuel type in particular fuel unit of measure; and
6. Total Fuel and Purchased Energy Costs in dollars.

Since the forecast for 2009/10 was comprised of 2 modelling segments, DISCO prepared reconciliation schedules for the two periods (i.e. – April 1, 2009 to September 30, 2009 and October 1, 2009 to March 31, 2010). The additional schedules supported the calculations for the two different VEP's used in the forecast.

Results

Our review began by agreeing the modeling assumption parameters to the underlying, supporting documentation. All inputs were agreed without exception. The supporting schedules, as explained above, were reviewed in detail with the NB Power employee responsible for the information. In most cases, and where readily available, source documentation was reviewed against the supporting schedules and found to adequately support the representations made. We also agreed the modelling guidelines as presented in the revised Schedule 6.2 and 6.15.2 to the Vesting PPA as described in Amendment No. 3 to the Vesting PPA. No exceptions were noted.

Following are the detailed results of our work.

Load Forecast

The load forecast data was reviewed with the senior load forecaster. We reviewed the methodology and procedures used to establish the annual load forecast. We note for the 2009/10 forecast that more work was performed in determining the impact on load reduction from initiatives established by Efficiency N.B. Specifically, Efficiency N.B. had each of their initiatives analyzed by NB Power technical staff and for the first time included estimates from the residential sector (previously only commercial and industrial reduction estimates were included).

We also noted that the spilt forecast between the two modelling segments contained different amounts for the overall load requirement with the second run (showing PLGS back "on-line") indicating a higher total forecasted load requirement than the first run. We would have assumed that the overall load forecast would not have changed based on the operational status of PLGS. It was explained that the second run would be higher since it reflects the actual operational status of each generating facility that results in increased transmission losses[3] while PLGS is off-line for the first half of the year. Since the first run reflects a notional load as if PLGS was operational, the forecast for the first half of the year includes a reduced transmission loss factor (from 3.5% to 2.5%) thereby decreasing the overall load required.

The load forecast study performed by GDS Associates, Inc. in July 2007 contained nine recommendations for improvements to the load forecast methodology. This study was DISCO's response to a BOARD order that the load forecast methodology be reviewed. We reviewed the progress NB Power has made in analyzing and implementing these recommendations and note that all have now been reviewed. Where deemed practical and of beneficial use, the GDS recommendations have been implemented in the preparation of the 2009/10 forecast.

We agreed the monthly load forecast data under the two scenarios to the respective Promod^{TM} output reports. No differences were noted.

Fuel Pricing Forecasts

The pricing assumptions are broken down into six main categories – Heavy Fuel Oil (HFO), natural gas (summer and winter strips), coal, petroleum coke, nuclear fuel, and auxiliary fuel components (e.g. – limestone, gypsum removal, etc.).

[3] Transmission losses have escalated while PLGS has been out of service due to the southern N.B. industrial load requirements being serviced from northern generating facilities.

HFO and natural gas pricing forecasts were agreed to external market quotations provided by commodity traders (e.g. – J. Aron, Morgan Stanley, NYMEX). In all cases the external forecasts were in agreement with the supporting documentation.

NB Power procures its coal supply through a request for proposal process and from its operating subsidiary, NB Coal. Contracts supporting the imported coal price forecasts were reviewed and the prices were re-calculated based on the provisions of each individual agreement. No significant variances were noted and the pricing amounts included in the supporting documentation appear to be in accordance with the supply contracts. Pricing for coal supplied by NB Coal is based on various operating costs of the subsidiary. We agreed the supporting documentation calculating the price per ton to information supplied directly by NB Coal's finance department. No variances were noted.

Petroleum coke is supplied through contracts with external parties and is blended with other fuels and burned at the Belledune and Coleson Cove generating facilities. The supply contracts were reviewed and the pricing formula, including various adders for freight, wharfage, and handling, were recalculated and agreed to the supporting information. No significant variances were noted.

Other ancillary costs and the nuclear fuel were reviewed to supporting documentation including supply contracts. Additional costs incurred to make the nuclear fuel ready for use were reviewed for consistency with the prior year. No issues were noted.

<u>Other Inputs</u>

Other variables in the ProMod^{TM} modeling assumption input summary (and corresponding supporting schedules) reviewed included:

- Forecasted CPI (inflation);
- Forecasted US-CDN dollar exchange rate;
- Foreign exchange and commodity hedges;
- External market pricing forecasts;

- Replacement energy forecast costs;

We were able to agree the input variables to the supporting documentation and related evidence. We reviewed the documentation with NB Power staff and the explanations given were reasonable in each of the circumstances. Variances from prior years were discussed and corroborated against other areas of the review. We noted no unreasonable explanation.

Reconciliation of Input Assumptions with ProMod^{TM} Output

(Scope of Work Reference 1 (i) c)

The ProMod^{TM} output used to establish the forecasted fuel and purchased power expense is comprised of three main components – fuel costs, fuel auxiliary costs and purchased power costs. As previously mentioned, the 2009/10 forecast is a consolidation of two different runs using the first six months from the first run and the second six months from the second run.

A sample of the more significant cost components was reviewed in detail with NB Power staff in an attempt to correlate the forecasted result with the underlying documentation. Because each run used a fundamentally different capacity factor for PLGS, many of the input criteria around fuel consumption and inventory levels were modified between the two scenarios. Whereas in the prior year we were able to use the annual data to perform our calculations, for this year the monthly data was used and then accumulated to compare to the output. In all cases, however, we were able to reproduce the ProMod^{TM} generated figures to within a reasonable variance. There were no unexpected outcomes in the report and all variances were adequately explained. It appears from our review that the output is consistent with the underlying assumptions and detailed inputs.

Reconcile ProMod™ to DISCO's forecasted Purchase Power Expense Calculations

(Scope of Work Reference 1 (ii) d, e, f & g)

Since the forecast included two different ProMod™ runs, DISCO prepared a summary of costs by fuel type/generation facility and the load to be supplied from the heritage assets for the two different periods, summarized as follows:

	Apr 09 – Sep 09	Oct 09 – Mar 10	TOTAL
Total cost of energy (from base heritage assets for vesting load)	$172 million	$366 million	$538 million
Vesting load (MWh)	4,023,800	5,293,900	9,317,700
Vesting energy price ($/MWh)	$42.817	$69.194	$57.713

For each calculation period, and on a month by month basis, we agreed the corresponding costs by fuel type/generation facility from the ProMod™ output to the summary spreadsheet. We also agreed the forecasted energy production by heritage asset from the ProMod™ output to the summary. No discrepancies were noted and we were able to recalculate the VEP for each period as indicated in the previous table.

Using the forecasted load requirement from heritage assets at point of receipt of 9,372,300 MWh, we were able to verify the fuel component of the vesting energy charge of $540.9 million[4].

Vesting Energy Charge - Contribution to fixed costs

The second component of the Vesting Energy Charge is the contribution to fixed costs as described in the Vesting PPA[5]. This payment from DISCO is intended to compensate GENCO for its operating, maintenance and administration costs and is a fixed amount adjusted for inflation each year. By fixing the amount of contribution, GENCO is incented to control these costs.

[4] See DISCO information package, April 30, 2009, Section 2, page 25, Table 2C
[5] Section 6.2.6 and schedule 1.1.30

The rate used for 2009/10 is $7.72/MWh representing a CPI adjusted increase from the 2008/09 figure. This rate is then applied against the load requirement of DISCO including any load needed to replace energy from PLGS while it is out of service. The total cap is set at 12 Terawatt-hours of energy. The requirement that the PLGS replacement energy be included in this calculation was clarified in Amendment 3 to the Vesting PPA[6].

The total load requirement for calculating the contribution to fixed costs is comprised of the heritage asset load of 9,372,300 MWh and the assumed production from PLGS of 1,579,700 MWh for a total of 10,952,000 (we note an immaterial difference of 100 MWh to the information package supplied by DISCO). We agreed the total load requirement of 10,952,000 MWh to the ProMod™ output data.

Applying the prescribed rate of $7.72 against the total load of 10,952 GWh produces a total contribution to fixed costs of $84.6 million.

Purchased Power Expense - Other Components - GENCO

Capacity Payment

Under sections 2.1 and 6.1 and schedule 1.1.17 of the Vesting PPA, DISCO has nominated 2,425.1 MW of GENCO's base load asset generating capabilities. For this capacity, DISCO is required to pay an annual capacity charge as specified in the agreement. We agreed the monthly charge as set out in the agreement at $10,416.67 and, given that DISCO did not alter its nomination of capacity, results in an annual charge of $303.1 million.

[6] See DISCO information package, April 30, 2009, Appendix B, Amendment No.3, Section 9.9 (describing new section 6.15.2 to the Vesting PPA)

Capacity Payment Adjustments

A total of $8.4 million for capacity payment adjustments are included in the forecast for 2009/10. The adjustments relate to additional capital costs incurred by GENCO that will bring future benefit to DISCO customers through increased efficiencies or operating cost reductions. We reviewed the individual adjustments and found them to be consistent with prior years in terms of amount and nature of expenditures.

Interruptible and Surplus Energy

Purchased power to supply interruptible and surplus customers is forecasted to increase to 372 GWh (7.2%) in 2009/10 as a result of higher expected demand from customers[7]. DISCO pays the incremental average cost of supply from GENCO after the in-province load has been serviced. The average rate for the forecast year is $80.32/MWh (2008/09 - $47.53/MWh).

We agreed the 372 MWh of demand to the load forecast data used in the ProMod™ assumptions. The increase in cost for this energy is consistent with the overall increase in fuel costs noted during our review. We also note that the increase has a negligible effect on the overall results of DISCO as any percentage increase in costs is offset with a corresponding increase in revenues.

Export Benefit Credit (Third Part Gross Margin Benefit)

DISCO receives a credit from GENCO for energy sales to third parties. The formula to determine the benefit was revised for 2009/10 and is outlined in Amendment No.3 to the Vesting PPA[8]. The forecast for 2009/10 indicates a credit of $31.7 million which is comparable to the expected credit for 2008/09 of $31.8 million (export benefit plus export benefit adjustment) but significantly lower than the actual result for 2007/08 of

[7] See DISCO information package, April 30, 2009, Section 1, page 9
[8] See DISCO information package, April 30, 2009, Appendix B, Amendment No.3, Schedule B (describing new Schedule 6.3 to the Vesting PPA)

$69.6 million. The lower benefit over the last two years is a direct result of the PLGS refurbishment as GENCO utilized more generating capacity to service in-province load leaving less for export sales.

We note that the amendment to schedule 3 of the Vesting PPA includes a provision to adjust the export benefit if PLGS does not restart on schedule (assumed to be October 1st, 2009 for purposes of the forecast).

We reviewed the calculations in support of the forecast and reviewed the amended calculations laid out in the revised Vesting PPA. No discrepancies were noted.

Ancillary Service Credit

DISCO receives a credit from GENCO for ancillary services provided by GENCO for such items as load regulation, spinning reserves and voltage support. The credit to DISCO is set out in section 5.2.1 of the Vesting PPA. The following table compares the ancillary service credit received from Disco over the last 3 years as compared to the current year forecast:

	Forecast	**2008/09**	**2007/08**	**2006/07**	**2005/06**
Ancillary Service Credit	5.6	5.4	6.0	4.3	2.4

Based on this comparison, the forecast appears reasonable.

Purchased Power Expense - NUCLEARCO

(Scope of Work Reference 1 (iii).i)

Similar to the arrangement with GENCO, DISCO's acquisition of energy from the PLGS is governed by a power purchase agreement referred to at the NuclearCo PPA. DISCO is entitled to all of the capacity of the PLGS less 30 MW that have been nominated by the Maritime Electric Company under a Unit Participation Agreement. Maximum energy available to DISCO is calculated at 5,029.5 GWh on an annual basis (605 MW x 24 hours x 365 days x budgeted capacity factor of 94.9% - the capacity factor considers planned and unplanned outages during the year).

The total forecasted cost for 2009/10 is $248.2 million and includes two components.

Purchased energy

The refurbished plant is expected to resume supply of energy on October 1, 2009 at a capacity factor of 94.9% providing 2,540,000 MWh to March 31, 2010. According to the NuclearCo PPA[9], the price per MWh was to be $67.60. The forecast used a price of $64.06. This discrepancy was intentional and reflects pending amendments to the NuclearCo PPA which have not yet been finalized. We therefore were unable to verify the price used in the forecast to an underlying agreement. If the approved rate was used, we note that the expense would have been higher by $9.0 million. Given the reasons stated in the information package[10], a reduced rate (as used in the forecast) appears reasonable although we are unable to comment on the quantum of the reduction.

The forecasted supply of energy from PLGS was agreed to the ProMod^{TM} output used to set the vesting energy price for the second half of the forecast year. No discrepancies were noted.

[9] Power Purchase Agreement, Point Lepreau Nuclear Generating Station, Schedule 1.1.22, Section II (3)(a)
[10] See DISCO information package, April 30, 2009, Section 2, page 38

NuclearCo Costs Embedded in Rates

While PLGS is undergoing refurbishment, DISCO receives replacement energy from GENCO. Section 143.1 of the Electricity Act governs the treatment of the cost of this replacement energy in that DISCO is to maintain a deferral account for the additional costs paid while PLGS is non-operational. The deferral account will be amortized over the extended life of the refurbished plant and the 2009/10 forecast includes an amortization expense of $3.7 million. The mechanics of the deferral account have recently been established by the parties but have not been reviewed by the Board. Additionally, we have not been asked to provide any commentary on the deferral account.

In order to establish a baseline to determine the additional costs to DISCO, the forecast includes a notional charge from PLGS as if it had been operational under normal circumstances over the out-of-service period. The forecasted notional production is set at 1,579,700 MWh at a prescribed price of $54.47/MWh. We agreed the production figure to the ProMod^{TM} output for the first run scenario noting a slight difference for the month of September. 84,700 MWh of energy were estimated for startup when PLGS resumes operational status and were not included in the notional production figure for the first 6 months of the forecast. This is reasonable as it will take a period of time for the plant to come up to full operational status during which time some incidental, actual production will occur. This production is included in the budgeted energy charge once PLGS returns to service.

The price used to determine the notional amount was compared to the rates prescribed by the NuclearCo PPA prior to the refurbishment. The following table summarizes this data:

	2009/10 (Notional)	**2008/09** (Notional)	**2007/08**	**2006/07**	**2005/06**	**2004/05**
Prescribed rate – 1st Threshold (per MWh)	54.47	53.83	53.19	52.74	52.14	$51.73
Percentage change from prior year	1.19%	1.20%	0.85%	1.15%	0.79%	-

Compared to the historical figures, and to the pricing mechanisms outlined in Schedule 1.1.22 and 1.1.26 of the NuclearCo PPA, the rate used to determine the notional amount for baseline energy purchases during the refurbishment period appears reasonable.

Purchased Power Expense – Other Sources

Energy purchases from other sources are comprised primarily from renewable energy generation facilities (wind farms) and to a lesser extent, non-utility generators. Each of these arrangements is governed by a Power Purchase Agreement.

Total load supplied from these sources represents 3.7 % of the total requirement. Since the renewable energy generators are new and have no production history, the production forecast for 2009/10 was based on the projections used in the business cases. Lacking actual production values, this appears to be a reasonable assumption. We did agree the total production for the forecast to the total generating capabilities of each generator and determined that the theoretical capacity exceeded the forecast.

We agreed the total forecasted expense of $39.6 million to the ProMod™ output. The monthly production forecast detail was then compared to the total monthly costs to determine an average price for each MWh. These average prices were then compared to supporting documentation. In all cases, the calculated average price/MWh compared to the rates contained in the support including escalation provisions during the forecasted fiscal year.

Conclusion

Appendix II details the individual components of the total forecasted purchased power expense of $1,194.7 million. Each component of this expense has been reviewed in the previous sections. Based on the review procedures conducted and the results obtained, nothing has come to our attention that would cause us to believe that DISCO's forecasted purchased power expense for the fiscal year ended March 31, 2010 is materially misstated. Further, the amount forecasted appears reasonable and plausible based on the results of our work.

Other Observations

Perhaps the most critical assumption made in preparing these forecasts was the back-in-service date of October 1, 2009 for the PLGS. Preparation of the preliminary background information used to establish this forecast would have begun late in the summer of 2008 and at that time, the best estimate for completion was October 1, 2009. This assertion is not disputed. The process used to set annual operating budgets for the NB Power group is extensive and lengthy. We reviewed this process in our report from last year's rate investigation. The process requires foundational assumptions to be set early in the process and the re-start date is certainly one of them.

We could not, however, complete our analysis without considering the potential impact of a postponement of the back in-service date. During the course of our review, we noted several areas which may be impacted if PLGS does not return to service on October 1, 2009. This is by no means a complete analysis of the impact of a delay, but rather ancillary observations made while conducting our review.

Amortization of PLGS Deferral Account

The current year forecast includes a charge of $3.7 million for the initial amortization of the deferral account. If the PLGS was not to re-start on October 1, 2009, this amount

would be reduced accordingly and eliminated if the re-start date was after March 31, 2010.

Vesting Energy Charge

The contribution to fixed costs is calculated using the forecasted energy required from GENCO to service the in-province load to a maximum threshold of 12,000,000 MWh of energy. The current year forecast includes an estimate of 10,952,100 MWh however if PLGS does not restart as planned, additional supply will be required from GENCO. We note that in 2008/09, the maximum threshold was used in the calculation while PLGS was out of service for the entire fiscal year. Assuming a restart date after March 31, 2010, it would seem plausible that the threshold would once again be achieved. This would increase the contribution to fixed costs charge from GENCO to DISCO by $8.1 million (12,000,000 less 10,952,100 x $7.72/MWh).

Export Benefit Credit

The export benefit credit figure of $31.7 million assumes that load supplied from the re-started PLGS will allow for energy sales to third parties during the second half of the fiscal year. If PLGS fails to start production before March 31, 2010, approximately $16.0 million of the export benefit to DISCO could be in jeopardy. Unlike past years where this credit was predetermined by the Vesting PPA, the recent amendment now allows for an adjustment if the PLGS re-start date is missed.

Impact on Embedded Costs

The forecast includes a charge of $162.1 million for actual energy production from PLGS for the second half of the fiscal year. This amount, as discussed previously, is a product of the expected energy production of 2,540 GWh at a budgeted rate of $64.06, less a $600,000 credit for ancillary services. The forecast also includes a notional charge for PLGS of $86.1 million determined on an assumed production amount as if PLGS had

been operating in the same condition as prior to the refurbishment. These costs, calculated under the NuclearCo PPA, are forecasted at $248.2 million.

If the plant does not restart before March 31, 2010, the notional amount of supplied energy would increase to 3,804 GWh[11] at the rate of $54.47/MWh increasing the embedded cost amount to $207.2 million. There would be no charge for actual production. The total costs calculated under the NuclearCo PPA would be decreased by $41.0 million.

This analysis is somewhat limited in that it does not consider the impact on the Vesting Energy Price due to a reduced capacity from PLGS for the entire fiscal year. Additionally, the incremental supply costs borne by GENCO would be added to the deferral account for future recovery from the rate payers. The delay, therefore, would not create an absolute savings, but a deferral of costs to future periods.

Summary

These potential impacts are summarized as follows:

	Area Identified	Potential Impact (Assume PLGS in-service date after March 31, 2010)
1	Amortization of PLGS Refurbishment Deferral Account	($3,700,000)
2	Vesting Energy Charge – Contribution to Fixed Costs	8,100,000
3	Export Benefit Credit	16,000,0000
4	NuclearCo PPA – Impact on Embedded Costs	(41,000,000)
Total potential reduction of DISCO's PURCHASED POWER EXPENSE		($20,600,000)

[11] See DISCO information package, April 30, 2009, Appendix B, Amendment No.3, Schedule A (describing new Schedule 6.2 to the Vesting PPA, Item 5)

PDVSA Settlement Deferral Account

Background

The deferral account captures the benefits accruing from the PDVSA settlement and returns them to customers over a 17 year time frame (the length of the original fuel supply agreement upon which the litigation was based). The settlement included an upfront cash component, and a new fuel supply agreement providing NB Power with an alternate fuel at a reduction from market price. NB Power will have fully realized the settlement value once the final fuel is delivered.

The PDVSA settlement was thoroughly reviewed during the 2007 rate hearing and again as part of the 2008 rate investigation. The August 23, 2007 decision by the Board approved the use of the deferral account and the February 22, 2008 decision made several orders affecting the account's operation. Our review will ensure that the Board's orders are incorporated into the supporting documentation used to generate the benefit included in the forecast for 2009/10.

Review of PDVSA Deferral Account

(Scope of Work Reference 2(i) & (ii).)

We reviewed the internal documentation that outlines the procedures, processes, documentation standards and accounting entries each of the subsidiary corporations use to account for the PDVSA Settlement Deferral Account transactions. We noted no significant changes from the prior year and once again found no issues with the processes as documented.

Total forecasted benefit to DISCO customers for 2009/10 and forward is $24.2 million representing a reduction from last year's benefit amount of $1.2 million. The benefit is comprised of an interest savings component and an amortization savings component, and reflects adjustments related to the in-kind portion of the settlement for market

fluctuations in commodity and freight prices as the actual fuel is delivered. We reviewed the underlying assumptions including forecasted interest rate, foreign exchange estimates, conversion factors and estimated value of the in-kind portion of the settlement and found them to be consistently calculated as in prior years. All supporting schedules were reviewed and agreed to the deferral account summary and a sample of calculations was re-performed without error.

Fuel Delivery

The original delivery plan included a portion of the settlement fuel to be utilized at Coleson Cove and had all of the fuel being received by June of 2009. Certain market and third party contractual conditions precluded using the settlement fuel at Coleson Cove and the entire quantity will be burned at Dalhousie. This has extended the final delivery date to April 2010. The fuel supply assumptions are consistent with those that we reviewed during our work on the fuel and purchased power expense and underlying ProMod^{TM} data found in the first section of this report.

In-Kind Valuation Adjustments

The "in-kind" value of the settlement was based on the difference between market values and the settlement price for the fuel. World market prices have fluctuated from the original forecasts and have impacted the estimated value of the settlement. For the forecast year, this amount has been estimated at $18.1 million and has been included in the deferral account calculation. The following table summarizes the cumulative expected value of the settlement as currently forecasted:

	Per 2009/10 Forecast	**Per 2008/09 Forecast**
Interest savings	$187,092,795	$186,330,712
Amortization savings	304,830,477	304,830,477
In-kind settlement adjustment for market fluctuations in commodity and freight prices	(18,078,281)	(4,818,596)
Estimated total cumulative savings	$473,844,991	$486,342,593

Interest rates

The interest rates used in the model consisted of a blend of short-term and long-term rates, plus the debt portfolio management fee. Short-term rates were applied to realized benefits (i.e. – as settlement fuel is received) until such time that a significant amount has accumulated. At this point the savings are calculated using the long-term rates under the assumption that the accumulated amount will be applied to reduce long-term debt. We agreed both the short-term and long-term interest rate assumptions to independent rate forecasts supplied by external parties. The forecast uses a short-term rate of 3.23% and a long-term rate of 4.79%. Overall the methodology is consistent with the prior year.

Conclusion

Our review of the PDVSA Settlement Deferral account indicated that all Board orders have been properly implemented. Our review produced no evidence that would indicate that the assumptions used and the methodologies implemented are not reasonable. We would conclude that the levelized benefit included in the forecast for 2009/10 is plausible in the circumstances.

APPENDIX I – Scope of Work

Forecasted Purchase Power Expense

(i) Review of Promod™ modeling assumption data:

a. Agree all inputs to underlying supporting information.
b. Provide comparison to prior year's Promod™ inputs and review variance explanations provided by NBP/DISCO staff.
c. Review Promod™ output for consistency with input assumptions.

(ii) Reconcile Promod™ Output information to amount(s) contained in DISCO's forecasted Purchase Power expense calculations:

d. Agree Promod™ generation amounts to forecasted energy requirements.
e. Agree Promod™ forecasted fuel costs for Disco to calculation of Vesting Energy Charge.
f. Verify calculations used to set the Vesting Energy Price for the 2009/2010 forecast as compared to provisions of the Power Purchase Agreements ("PPA's").
g. Compare 2009/2010 Vesting Energy Price calculation inputs with prior year and review variance explanations provided by DISCO staff.

(iii) Review other components of forecasted Power Purchase Expense:

h. Review capacity payment calculations and agree to PPAs.
i. Review other "cost items" and compare to prior year. Obtain variance explanations from DISCO staff.

(iv) Reconcile above outcomes to purchase power expense contained in the forecasted financial statements for the fiscal year ended March 31, 2010.

APPENDIX I – Scope of Work (continued)

PDVSA Settlement Deferral Account

Review of policies, procedures, and methodologies used to calculate the PDVSA Deferral Account balance and the adjustment to Purchase Power expense for the test year, including:

(i) A recalculation of the Regulatory Deferral Calculation:

a. Review of changes to original estimates (true-up to actual);
    i. update to the fuel delivery schedule,
    ii. verification of conversion factors used in the calculations,
    iii. verification of updated prices used to determine the estimated cost savings per unit of supply, and.

b. Proper implementation of changes ordered by the Board in the decision of February 22, 2008; (or)

c. Comparison of results if Board orders were implemented to those that were included in the forecast.

(ii) Reconciliation of calculated amounts to forecasted purchase power expense.

APPENDIX II – DISCO Summary of Purchase Power Expense

Source of Expense	2009/2010 Forecast (in millions $)	Page Reference
[A] GENCO		
Vesting energy charge		
Fuel component	$540.9	6
Contribution to fixed costs	84.6	13
Capacity payment	303.1	14
Capacity payment adjustments	8.4	15
Interruptible and surplus energy	29.8	15
Export benefit (recovery)	(31.7)	15
Ancillary service credit (recovery)	(5.6)	16
	929.5	
[B] NUCLEARCO		
Purchased power	162.1	17
Additional costs embedded in rates	86.1	18
	248.2	
[C] OTHER	**39.6**	20
[D] PDVSA SETTLEMENT BENEFIT (RECOVERY)	**(26.3)**	24
[E] PLGS DEFERRAL AMORTIZAITON	**3.7**	18
TOTAL PURCHASE POWER EXPENSE **[A]+[B]+[C]+[D]+[E]**	**$1,194.7**	

(Note: Information compiled from Tables 2A, 2B and 2H – DISCO Information Package, April 30, 2009).