NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF an Investigation into the necessity for the three per cent increase in charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation pursuant to section 24 of the *Energy and Utilities Board Act*

Information Package relating to New Brunswick Power Distribution and Customer Service Corporation forecasted revenues and costs for 2010/2011

28 May, 2010

Volume 1 of 1
Board Reference: 2010-006

Énergie NB Power

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF the Energy and Utilities Board Act, Chapter E-9.18

-and-

IN THE MATTER OF an Investigation into the necessity for the three per cent increase in charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation pursuant to section 24 of the *Energy and Utilities Board Act*

INFORMATION PACKAGE

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NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF an Investigation into the necessity for the three per cent increase in the charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation pursuant to section 24 of the *Energy and Utilities Board Act*

ORDER

WHEREAS the New Brunswick Energy and Utilities Board (Board) has been directed by the Minister of Energy pursuant to section 24 of the *Energy and Utilities Board Act (Act)* to make an investigation into the necessity for the 3% increase in the charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation (Disco) to be effective June 1, 2010.

AND WHEREAS the Board has determined that, as part of this investigation, there will be an opportunity for public participation;

AND WHEREAS the Board has set out the public participation process that will be used during the course of this investigation, a copy of which process is attached hereto as Exhibit "A";

AND WHEREAS the Board intends, subject to such changes that may be required from time to time, to follow the process outlined in Exhibit "A";

NOW THEREFORE IT IS ORDERED THAT:

(a) Disco shall make available for inspection by Board staff and/or its consultants, all records or documents that are requested by the Board and that relate to the matter under investigation;

(b) Disco shall file with the Board and shall make available for review both in its business offices and on its website on or before 12 noon May 28, 2010 a complete package of the evidence relating to its forecasted revenues and costs for 2010/2011.

(c) Disco shall respond to written questions submitted by registered participants by 12 noon June 14, 2010.

(d) In the event there is an issue with respect to the adequacy of a response, registered participants must inform Disco and the Board in writing no later than 4 p.m. June 15, 2010 with their reasons as to why the response is not adequate. Disco must respond in writing to any objection that has been raised no later than 4 p.m. June 16, 2010.

(e) Disco shall appear at a public hearing on June 22, 2010 commencing at 9:30 a.m. in the forenoon at the Delta Brunswick Hotel, Ballroom C, Saint John, New Brunswick and from day-to-day thereafter as required.

(f) Disco shall place a copy of this Order on file for examination by interested parties during business hours in Disco's business offices and shall further place a copy of this Order on its website by May 14, 2010.

DATED at the City of Saint John, New Brunswick, this 5th day of May, 2010.

BY THE BOARD

Lorraine R. Légère
Board Secretary
New Brunswick Energy and Utilities Board

EXHIBIT "A"

INFORMATION WITH RESPECT TO THE PUBLIC PARTICIPATION PROCESS TO BE USED BY THE NEW BRUNSWICK ENERGYAND UTILITIES BOARD IN ITS INVESTIGATION

The New Brunswick Energy and Utilities Board (the Board) is investigating the necessity for the 3% increase in the charges, rates and tolls of the New Brunswick Power Distribution and Customer Service Corporation (Disco) to be effective June 1, 2010.

This investigation is limited to Disco's forecast of its revenues and costs and does not include an investigation of any other company.

The Board has set the schedule for the public participant segment of this investigation as follows:

- **Participants who register with the Board will be permitted to submit written questions to Disco and participate at the hearing by asking questions and making comments in accordance with the following schedule:**

Disco to file information with the Board and to make the information available at its business offices and on its website	12 noon May 28, 2010
Participants to register with the Board and Disco	4 p.m. May 28, 2010
Participants to submit written questions to Disco with a copy to the Board	4 p.m. June 4, 2010
Disco to respond to written questions	12 noon June 14, 2010
Participants to inform Disco and the Board in writing if they are not satisfied with the adequacy of a response and the reasons why they are not satisfied	4 p.m. June 15, 2010
Disco to respond in writing to any objection that has been raised	4 p.m. June 16, 2010
The Board to provide written directions with respect to any response that has been challenged	4 p.m. June 17, 2010

Public Hearing commences	9:30 am June 22, 2010
Note: ➢ Questions will be confined to the issue of "Disco's forecast of revenues and costs". As such, questions that are outside the scope of this investigation will not be permitted. ➢ The Board notes that this is an investigation and not a rate application and as such, the process has been varied accordingly.	

- **Those who do not wish to participate at the hearing may provide written comments to the Board and Disco on or before June 15, 2010.**

- In addition to the above- noted schedule, the Board has retained an independent financial consultant who is conducting a review and who will provide a written report to the Board. The report will be available by June 11, 2010 and interested parties may obtain a copy by contacting the Board.

- Participants who register with the Board will have an opportunity to question the consultant in relation to his report during the hearing.

- Disco will also have the opportunity to question the consultant.

At the hearing on June 22, 2010, the Board intends to proceed as follows:

- ➢ Disco will present its evidence;
- ➢ Board Counsel will question Disco witnesses on their evidence;
- ➢ Registered participants will be permitted to question Disco witnesses on issues not canvassed by Board Counsel;
- ➢ The independent financial consultant will present his evidence;
- ➢ Board Counsel will question the consultant on his evidence;
- ➢ Disco will question the consultant on his evidence;
- ➢ Registered participants will be permitted to question the consultant on issues not previously canvassed by either Board Counsel or Disco.
- ➢ Registered participants may offer final comments and submissions.

INVESTIGATION of ELECTRICITY RATE INCREASE

NOTICE

The New Brunswick Energy and Utilities Board (Board) has been directed by the Minister of Energy to investigate the necessity for the three per cent increase in electricity rates for customers of New Brunswick Power Distribution and Customer Service Corporation (Disco) that will take effect on June 1, 2010 and to report its findings to the Minister of Energy. The Board believes that it is in the public interest for the investigation to be completed as quickly as possible.

The Board has ordered Disco to file with the Board, by May 28, 2010 a complete package of the evidence relating to its forecasted revenues and costs for 2010/2011. This information will be posted on Disco's website by May 28, 2010 and is also available by contacting Disco.

In addition, the Board has retained an independent financial consultant to review certain aspects of the Disco information and to provide the Board with a report on his findings. This report will be available by June 11, 2010 and interested parties may obtain a copy by contacting the Board.

A public hearing will begin at 9:30am on June 22, 2010 at the Delta Brunswick Hotel, Ballroom C, Saint John.

An investigation is different in nature from a review that would occur in relation to an application by Disco. The investigation by the Board will be limited to a review of Disco's forecasted revenues and costs for the 2010/2011 year. The Board will not investigate the allocation of costs between customer classes nor the specific rate design used by Disco.

Members of the public may participate in one of two ways:

(a) Provide a written submission to the Board by June 15, 2010; or
(b) Participate in the public hearing.

Parties who wish to participate in the public hearing must register with the Board and Disco by May 28, 2010.

Parties who register may submit written questions to Disco by 4 pm June 4, 2010. Disco will respond to the questions by noon June 14, 2010. Parties, who do not consider the response by Disco to be adequate, must inform the Board and Disco, in writing, by 4 pm June 15, 2010 with their reasons as to why the response is not adequate. Parties will also be able to ask questions and provide submissions at the public hearing. Further information is available on the Board's website or by contacting the Board.

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OVERVIEW

On April 12, 2010, the Minister of Energy directed the Energy and Utilities Board ("EUB") pursuant to section 24 of the *Energy and Utilities Board Act,*

> *"to investigate the necessity for the three per cent increase in electricity rates for customers of New Brunswick Power Distribution and Customer Service Corporation ("Disco") that will take effect on June 1, 2010 and to report its findings to the Minister of Energy."* [1]

Pursuant to the above directive and by Order dated May 05, 2010[2], the EUB ordered Disco to

> *"file with the Board, on or before 12 noon May 28, 2010, a complete package of the evidence relating to its forecasted revenues and costs for 2010/11."*

This package contains the specific information requested by the EUB.

The budgeted statement of earnings for 2010/11 is provided in Table A.

[1] The EUB Notice appears under Tab – Notice.

[2] The EUB Order appears under Tab – Order.

Table A

NB Power Distribution and Customer Service Corporation
Budgeted Statement of Earnings
Fiscal Years Ending March 31
(in millions $)

Section	Component	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	**Revenues**	$ 1,340.8	$ 1,272.6	$ 68.2	$ 1,335.1	$ (62.5)	$ 1,263.2
	Expenses						
(2)	Purchased power	1,031.8	1,092.2	(60.4)	1,194.7	$ (102.5)	971.1
(3)	Transmission	66.2	63.6	2.6	62.7	$ 0.9	60.0
(4)	Operations, maintenance & administration (OM&A)	123.3	120.5	2.8	120.8	$ (0.3)	114.4
(5)	Amortization	38.1	36.7	1.4	37.3	$ (0.6)	35.4
(6)	Taxes (excluding special payments in lieu of income taxes)	11.0	10.9	0.1	11.0	$ (0.1)	11.3
(7)	Interest expense	33.1	35.9	(2.8)	46.2	$ (10.3)	37.5
(8)	Special payments in lieu of income taxes	10.8	(27.0)	37.8	(43.7)	$ 16.7	10.8
	Total expenses	1,314.3	1,332.8	(18.5)	1,429.0	(96.2)	1,240.5
(9)	**Net earnings (loss)**	$ 26.5	$ (60.2)	$ 86.7	$ (93.9)	$ 33.7	$ 22.7

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

* 2010/11 budgeted revenues at rates effective July 1, 2010

A three per cent increase in rates, an increase in energy sales, a decrease in purchased power costs from a 2009/10 high, and the implementation of cost reduction strategies will allow Disco to cover its budgeted expenses, and have positive net earnings. The budgeted net earnings will result in pre-tax interest coverage of 1.17 times.

Without the three per cent increase in rates, Disco's revenue would be approximately $29.6 million lower or $1,311.2 million, after tax net earnings would drop to approximately $5 million and interest coverage would be 0.62 times.

Because revenues were not sufficient to cover expenses in 2009/10, a useful comparison year is 2008/09. When comparing the 2010/11 budget (column 1) to 2008/09 actual results (column 6), total expenses have increased by $73.8 million or six per cent ($1,314.3 million - $1,240.5 million). The increase is mainly related to higher purchased power, transmission, OM&A and amortization expenses between the two years. The three per cent rate increase in 2009/10 did not recover all of the cost increases for that year, resulting in a net loss, yet these recurring expenses remain in 2010/11. This contributes to the need for a three per cent in 2010/11.

Net earnings in 2010/11 are required given the possible variability in operating results. Consistent with the evidence provided in prior rate reviews, the level of net earnings budgeted provides a minimum safeguard for factors outside management's control such as changes in weather, hydro generation and export margins which can result in significant swings in year-to-year results and in variances between budgets/forecasts and actual results.

The three per cent increase in rates in 2010/11 will assist in enabling Disco to gradually move toward a position where it is able to service all of its debt obligations, including payments of interest and repayment of outstanding debt when it comes due, and fund capital expenditures required to ensure the safe, efficient, reliable distribution of electricity while maintaining a reasonable level of equity through retained earnings.

Each component of Disco's budgeted expenses and revenues in Table A is discussed in a separate section within this document. Where applicable, additional information has been provided as attachments or appendices to further support the figures presented.

KEY FINANCIAL ASSUMPTIONS

Disco's budget for 2010/11 is based on management's best estimates of financial and operating assumptions as of early April 2010. Key assumptions supporting Disco's 2010/11 budgeted revenues and expenses are provided below.

- Disco's in-province revenue from energy sales includes a three per cent increase in rates effective July 1, 2010.
- In-province energy sales are based on the 30-year average weather temperatures (4,776 heating-degree-days).
- All existing industrial transmission customers are expected to continue operating.
- Hydro performance is based on long-term average hydro flows (equating to 2,654.4 GWh).
- Purchased power from wind driven generators is forecasted to total 734 GWh and represents five per cent of Disco's overall energy requirements.
- Benefits from export sales committed to Disco under the Vesting Agreement totals $43.4 million.
- The Point Lepreau Generating Station ("PLGS") is not expected to return to service in 2010/11.
- The PLGS regulatory deferral in the *Electricity Act*, s. 143.1 results in certain deferred expenses being recovered from customers over the new service life of the PLGS. This has no impact on Disco's revenue requirement in 2010/11.
- The impact of a non-union staff reduction program, including casual, temporary and regular employees is included in OM&A.
- The volatility in fuel and purchased power prices and the Canadian dollar are managed through the NB Power Group's forward purchasing program.

PLANNING PROCESS and TIMELINE

On October 29, 2009, the Province of New Brunswick executed a Memorandum of Understanding (MOU) with the Province of Québec under which substantially all of the assets of NB Power were to be sold to Hydro-Québec.

NB Power's normal planning cycle was affected by the MOU and the following timeline details the impact on the process.

On December 18, 2009, the New Brunswick Power Boards of Directors ("Boards of Directors") received a Draft 2010/11 budget prepared under the assumption that the NB Power Group would continue to operate with its existing ownership and organizational structure. The Draft 2010/11 budget contained budgets for each of the companies in the NB Power Group, including Disco.

The Draft 2010/11 budget represented a contingency plan in the event that the proposed sale of NB Power assets to Hydro-Québec was not executed on or before March 31, 2010. Because of this, the Boards of Directors approval of the Draft 2010/11 budget was not requested or given at the December meeting.

On March 24, 2010, the Province of New Brunswick announced that the Hydro-Québec transaction would not be completed. NB Power was required to review and revise the 2010/11 budget.

Budget changes at the NB Power Group level were prepared and presented to the Boards of Directors at a meeting on April 6, 2010. At this time, updated information for each of the companies in the NB Power Group was not finalized. On the basis of the information presented, the Boards of Directors approved the Draft 2010/11 budget subject to the following revisions as presented on April 6, 2010

1. delay in the planned three per cent rate increase by three months (from April 1, 2010 to July 1, 2010)

2. supply cost changes as a result of more favourable generation mix and short-term opportunities to purchase energy at lower cost
3. changes to the Point Lepreau refurbishment project completion date, and
4. implementation of a cost saving program, expected to result in savings for the NB Power Group of $20 million annually, commencing in fiscal 2011/12**.**

On April 6, 2010, the Board of Directors of Disco authorized a three per cent rate increase across all customer classes, effective as soon as all notice requirements could be met.

On May 21, 2010, the Boards of Directors were provided with revised 2010/11 budgets for each of the companies in the NB Power Group, including Disco. These budgets were based on the information included in the Draft 2010/11 budget document, updated to incorporate the revisions approved by the Boards of Directors on April 6, 2010. Disco's revised earnings in 2010/11 are budgeted to be $26.5 million.

The following Table B provides information on the revisions to Disco's budget that improved net earnings from $16.0 million to $26.5 million.

Table B

Revisions to Disco's 2010/11 Budget
(in millions $)

	Component	(1) Impact on 2010/11
(1)	Draft 2010/11 budgeted net earnings	$ 16.0
	Impact Of Revisions	
(2)	Draft 2010/11 budgeted net earnings before payments in lieu of income taxes	22.5
(3)	Reduction in purchased power costs	34.2
(4)	Reduction in revenue due to reduced load	(11.4)
(5)	Point lepreau refurbishment extension	
(6)	- amortization savings	2.0
(7)	- interest savings	1.0
(8)	Delay in rate increase implementation	(8.3)
(9)	Cost savings opportunities (costs in 2010/11)	(2.7)
(10)	Revised earnings before payments in lieu of income taxes	37.3
(11)	Payment in lieu of income taxes	(10.8)
(12)	**Revised budgeted net earnings**	$ 26.5

<u>REDUCTION IN PURCHASED POWER COSTS – TABLE B, LINE 3</u>

The reduction in load and changes in internal generation mix, including the ability to service some of the in-province load with purchases rather than using more expensive internal generation sources, caused purchased power costs to decrease by $34.2 million.

<u>REDUCTION IN REVENUE DUE TO REDUCED LOAD – TABLE B, LINE 4</u>

Reductions in revenue of $8.8 million were primarily due to load changes in the general service and industrial customer classes. Interruptible/Surplus revenue was reduced by $2.6 million due to lower supply costs.

<u>POINT LEPREAU REFURBISHMENT EXTENSION – TABLE B, LINE 6, 7</u>

The extension of the Point Lepreau refurbishment project through March 2011 avoids one month of deferral amortization of $2.0 million and deferral related interest of $1.0 million in 2010/11.

DELAY IN RATE INCREASE IMPLEMENTATION – TABLE B, LINE 8

Disco's Draft 2010/11 budget assumed a three percent rate increase effective April 1, 2010. The information provided to the Board of Directors on April 6, 2010 assumed a delay in implementing the rate increase until July 1, 2010. This caused a reduction in revenue of $8.3 million.

COST SAVINGS OPPORTUNITIES (COSTS IN 2010/11) – TABLE B, LINE 9

In developing the costs savings strategy, management focused on addressing cost savings through organizational changes, including

- Reduction in vice-presidents from eight to five, realizing organizational synergies in complementary areas of the business
- A staff reduction program, including casual, temporary and regular employees, while minimizing any negative impact to customer-facing processes
- Repatriation of some outsourced services

The impact to Disco in 2010/11 is an increase in OM&A costs of $2.7 million. This investment in future cost reduction consists of costs associated with the staff reduction program for Disco and Disco's appropriate share of Shared Service and Corporate Service staff reduction costs. These costs are partially offset by savings in labour for a partial year for individuals leaving as part of the staff reduction program, elimination of hired services, and the decision not to fill specific vacancies within Disco. The first full year of savings will be realized beyond 2010/11.

MATERIALS SUPPLIED

The balance of the package is organized as follows

- **Financial Details** – provides key assumptions and details on the key drivers and impacts of the year-over-year variances in Disco's budgeted revenues and costs
- **Appendices** – contains additional information to provide further context for Disco's forecasted revenues and cost

SECTION 1 – BUDGETED REVENUE (AT RATES EFFECTIVE JULY 1, 2010[1])

For 2010/11, the total budgeted revenue is $1,340.8 million (line 3, column 1), which assumes a three per cent rate increase effective July 1, 2010. Total revenue is made up of revenue from energy sales and miscellaneous revenue as shown in Table 1A.

Table 1A

Revenue
Fiscal Years Ending March 31
(in millions $)

	Component	(1) 2010/11B	(2) 2009/10E	(3) Variance (1) - (2)	(4) 2009/10B	(5) Variance (2) - (4)	(6) 2008/09A	(7) Table Reference
(1)	Revenue from energy sales	**$1,299.9**	$1,232.7	$ 67.2	$ 1,296.0	$ (63.3)	$1,222.5	Table 1C
(2)	Miscellaneous revenue	**40.9**	39.9	1.0	39.1	0.8	40.7	Table 1F
(3)	Total forecasted revenue (at rates effective July 1, 2010)	**$1,340.8**	$1,272.6	$ 68.2	$ 1,335.1	$ (62.5)	$1,263.2	

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

The accompanying sections will outline the following in more detail

- budgeted energy sales
- revenue from sales of power
- miscellaneous revenue (from non-energy activities)

BUDGETED ENERGY SALES

During the winter of 2009/10, Disco completed a 10-year Load Forecast for the 2010 to 2020 period. The first year of this Load Forecast was used to prepare Disco's 2010/11 budgeted sales. Attachment to Section 1 entitled "Energy Sales and Revenue Budget Development" includes more details on the forecast methodology.

[1] The rate increase is actually effective June 1, 2010, but was assumed to be implemented July 1, 2010 in the budget. This represents $2.5 million of unbudgeted revenue.

The major assumptions used to budget 2010/11 sales include

- Gross Domestic Product growth of 1.7 per cent in 2010/11 based on the Provincial Government's Economic Update released in December 2009
- Known major industrial closures, additions and load changes based on account manager input and public announcements
- The addition of 3,661 new year-round residential customers in 2010/11 based on historical customer growth and population projection
- Normal weather (4,776 heating-degree-days) as defined by Environment Canada's 30-year average
- Estimates of energy reductions from Efficiency New Brunswick's Residential, General Service and Industrial programs, as well as non-program driven energy conservation savings
- Penetration of electric space & water heating and air conditioning based on 2008 Energy Planning Survey results

REVENUE FROM ENERGY SALES - TABLE 1A, LINE 1

Revenue for each customer class is budgeted from the energy sales, unit rate trend analysis and billing determinants. This process is described in more detail in the Attachment to Section 1.

In the budget, a three per cent rate increase was assumed to be implemented on July 1, 2010. The three per cent rate increase is equally applied to all charges, with the exception of charges within the Residential class. The Residential monthly service charge is not increased again this year. As well, the declining block was eliminated in compliance with the EUB's February 2008 decision. The combined Residential changes result in a three per cent average rate increase to the class.

BUDGETED ENERGY SALES VOLUME

Table 1B shows the total budgeted, forecasted and actual energy sales volumes by customer class for 2010/11, 2009/10 and 2008/09 respectively.

Table 1B

Energy Sales, Volume (Energy)
Fiscal Years Ending March 31
(GWh)

	(1) 2010/11B	(2) 2009/10E	(3) Variance (1) - (2)	(4) 2009/10B	(5) Variance (2) - (4)	(6) 2008/09A
(1) Residential	**5,196**	5,032	164	5,114	(82)	5,036
(2) General Service	**2,357**	2,360	(3)	2,354	6	2,372
(3) Industrial Distribution	**673**	654	19	772	(118)	672
(4) Industrial Transmission	**3,627**	3,176	451	3,624	(448)	3,344
(5) Industrial Interruptible	**178**	303	(125)	372	(69)	349
(6) Wholesale	**1,157**	1,163	(6)	1,221	(58)	1,207
(7) Non-metered	**76**	75	1	75	-	75
(8) Total Sales of Power	**13,264**	12,763	501	13,532	(769)	13,055

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Total budgeted sales volume is projected to increase by 501 GWh (line 8, column 3) in 2010/11. An analysis of the budgeted sales volume increase in 2010/11 compared to the 2009/10 full year forecast is as follows

RESIDENTIAL – TABLE 1B, LINE 1

Residential, which includes year-round and seasonal households, churches, and farms, represents roughly 33 per cent of the total net increase in energy sales. The 164 GWh (line 1, column 3) increase in sales reflects warmer weather (91 GWh) in 2009/10 compared to the 30-year normal[2] and continued growth (73 GWh).

GENERAL SERVICE – TABLE 1B, LINE 2

The General Service classification comprises mostly commercial and institutional establishments. The 3 GWh (line 2, column 3) decrease in General Service sales mainly results from the price elasticity effect of a real price increase of electricity in 2009 and the delayed result of low GDP in 2008 and negative growth in 2009, which are partially offset by the return to normal weather (21 GWh).

[2] 2010/11 budgeted energy sales are based on the return to 30-year average temperatures (4,776 heating-degree-days). 2009/10E is 141 heating-degree-days warmer than normal, based on actual temperatures from April to December and normal temperatures from January to March.

INDUSTRIAL DISTRIBUTION – TABLE 1B, LINE 3

The Industrial Distribution classification includes customers involved in the extraction of raw materials or in the manufacturing and processing of goods. The 19 GWh (line 3, column 3) increase in Industrial Distribution budgeted sales results from an expected return to more historical operating levels for customers in the class.

INDUSTRIAL TRANSMISSION – TABLE 1B, LINE 4

Industrial Transmission includes customers involved in the extraction of raw materials or in the manufacturing and processing of goods and that are generally larger than those supplied from the distribution system. The 451 GWh (line 4, column 3) increase in Industrial Transmission represents the majority of the total increase in energy sales. Industrial Transmission growth is being driven by the drilling of a second Potash mine near Sussex, return to normal operations for many customers and a customer firming up a portion of Interruptible load. Lower than budgeted sales of 448 GWh (line 4, column 5) in 2009/10 mainly resulted from the closure of Blue Note Mines and production shutdowns due to market conditions during the year.

INDUSTRIAL INTERRUPTIBLE – TABLE 1B, LINE 5

Industrial Interruptible is comprised of six Industrial Transmission customers who purchase a portion of their energy requirements as Interruptible or Surplus energy and are subjected to curtailment of this load upon ten minutes notice. The 125 GWh (line 5, column 3) decrease in Industrial Interruptible is mainly due to a customer firming up a portion of Interruptible load.

WHOLESALE – TABLE 1B, LINE 6

The Wholesale class includes energy sales to two municipal utilities, Saint John Energy and Edmundston Energy. This class is comprised of Residential, General Service and Industrial Distribution customers located within these service territories. The 6 GWh (line 6, column 3) decrease in Wholesale sales results mainly from two renewable energy projects coming online in 2010/11 within Wholesale territory, lower General Service sales, as well as an Industrial Distribution customer served by Edmundston Energy moving to the transmission system and becoming a customer of Disco. These factors are partially offset by the return of normal weather in 2010/11 (16 GWh).

NON-METERED – TABLE 1B, LINE 7

Non-metered sales, which include streetlights and other miscellaneous unmetered services, are budgeted to grow by one GWh (line 7, column 3) driven by population growth.

BUDGETED REVENUE

Table 1C shows the budgeted, forecasted and actual revenue from energy sales for 2010/11, 2009/10 and 2008/09 respectively.

Table 1C

Revenue from Energy Sales
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B***	(2) 2009/10E	(3) Variance (1) - (2)	(4) 2009/10B	(5) Variance (2) - (4)	(6) 2008/09A
(1) Residential	**$ 586.5**	$ 554.6	$ 31.9	$ 564.8	$ (10.2)	$ 539.0
(2) General Service	**271.8**	263.1	8.7	265.1	(2.0)	257.1
(3) Industrial Distribution	**64.7**	61.3	3.4	71.8	(10.5)	63.5
(4) Industrial Transmission	**244.8**	215.6	29.2	237.6	(22.0)	224.4
(5) Industrial Interruptible	**9.0**	16.5	(7.5)	32.2	(15.7)	18.6
(6) Wholesale	**99.5**	98.5	1.0	100.9	(2.4)	97.9
(7) Non-metered	**23.6**	23.1	0.5	23.5	(0.4)	22.0
(8) Total Revenue	**$ 1,299.9**	$ 1,232.7	$ 67.2	$ 1,296.0	$ (63.3)	$ 1,222.5

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals
* at rates effective July 1, 2010

Total revenue from energy sales is budgeted to increase by $67.2 million (line 8, column 3) or 5.5 per cent in 2010/11 compared to the 2009/10 full year forecast. This increase is attributable to

- a three per cent increase in rates effective July 1, 2010
- a budgeted increase in sales volume (see Table 1B)
- return to normal weather in 2010/11

Table 1D provides a calculated average breakdown of the year-over-year variance (2010/11 budget to 2009/10 full year forecast) resulting from changes in sales volume and changes in the price (average unit rate).

Table 1D

Year-Over-Year Breakdown of Revenue Variance
Fiscal Year 2010/11B - 2009/10E
(in millions $)

		(1) Variance due to Non-Weather Load Changes	(2) Variance due to Weather Effect	(3) Variance due to Price (Unit Rate) Changes	(4) Variance due to Supply Cost Changes	(5) Total Variance
(1)	Residential	$ 9.7	$ 8.4	$ 13.8	$ -	$ 31.9
(2)	General Service	(2.2)	1.9	9.0	-	$ 8.7
(3)	Industrial Distribution	1.8	-	1.6	-	$ 3.4
(4)	Industrial Transmission	30.6	-	(1.4)	-	$ 29.2
(5)	Industrial Interruptible	(6.8)	-	-	(0.7)	$ (7.5)
(6)	Wholesale	(1.8)	1.3	1.5	-	$ 1.0
(7)	Non-metered	0.3	-	0.2	-	$ 0.5
(8)	Total	$ 31.6	$ 11.6	$ 24.8	$ (0.7)	$ 67.2
(9)	% of total	47.0%	17.2%	36.8%	-1.0%	

As indicated above, $31.6 million (line 8, column 1) or 47.0 per cent of the 2010/11 budgeted revenue increase is attributable to the budgeted increase in energy sales volume (non-weather related). As well, $11.6 million (line 8, column 2) or 17.2 per cent of the variance results from a return to normal weather in 2010/11.[3]

The price variance on firm energy sales is $24.8 million (line 8, column 3) or 36.8 per cent. The three per cent rate increase effective July 1, 2010 accounts for $29.4 million of the price variance, offset by lower Industrial Transmission unit rates. In the 2009/10 full year forecast, industrial production shutdowns resulting from market conditions put upward pressure on the Industrial Transmission unit rate. Industrial Transmission customers are budgeted to return to more normal operating conditions in 2010/11.

The remaining $0.7 million (line 8, column 4) negative variance results from lower average supply costs, which decreases Interruptible revenue. Interruptible energy is

[3] 2009/10E is 141 heating-degree-days warmer than normal, based on actual temperatures from April to December and normal temperatures from January to March.

priced based on Disco's incremental average cost of supply, plus the applicable on-peak/off-peak adder. Interruptible revenue is not impacted by general rate increases.

Table 1E shows the budgeted, forecasted and actual unit rates for 2010/11, 2009/10 and 2008/09 respectively.

Table 1E

Unit Rates

Fiscal Years Ending March 31

($ per MWh)

		(1)	(2)	(3)	(4)	(5)	(6)
		2010/11B*	2009/10E	Variance (1) - (2)	2009/10B	Variance (2) - (4)	2008/09A
(1)	Residential	**$ 112.88**	$ 110.21	$ 2.66	$ 110.44	$ (0.22)	$ 107.03
(2)	General Service	**115.32**	111.48	3.83	112.63	(1.14)	108.39
(3)	Industrial Distribution	**96.14**	93.73	2.41	93.01	0.73	94.49
(4)	Industrial Transmission	**67.49**	67.88	(0.39)	65.57	2.31	67.11
(5)	Industrial Interruptible	**50.56**	54.46	(3.89)	86.65	(32.19)	53.30
(6)	Wholesale	**86.00**	84.69	1.30	82.64	2.06	81.11
(7)	Non-metered	**310.53**	308.00	2.53	313.13	(5.13)	293.33
(8)	Weighted average unit rate	**$ 98.00**	$ 96.58	$ 1.42	$ 95.77	$ 0.81	$ 93.64

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals
* at rates effective July 1, 2010

The average unit rate is budgeted to increase by $1.42/MWh (line 8, column 3) or 1.5 per cent in 2010/11 mainly due to the July 1, 2010 three per cent rate increase, partially offset by lower Industrial Transmission budgeted unit rates in 2010/11. The Interruptible unit rate decrease of $3.89/MWh (line 5, column 3) is due to budgeted supply cost reductions in 2010/11.

Industrial rates include both a demand and energy charge, which impact a customer's unit rate. For example, a customer that decreases its production output (as was the case in the 2009/10 forecast) will have a higher average unit rate because the energy requirements for the customer will decrease, while maintaining a similar peak demand. Industrial Transmission customers are budgeted to return to more normal operating conditions in 2010/11, which results in a lower average unit rate.

MISCELLANEOUS REVENUE – TABLE 1A, LINE 2

Please refer to Table 1F for the breakdown of miscellaneous revenue (from non-energy activities).

Table 1F

Miscellaneous Revenue
Fiscal Years Ending March 31
(in millions $)

		(1)	(2)	(3)	(4)	(5)	(6)
		2010/11B*	2009/10E	Variance (1) - (2)	% change (3) / (2)	2009/10B	2008/09A
(1)	Connection revenue	**$ 2.9**	$ 2.7	$ 0.2	7.4%	$ 2.9	$ 2.7
(2)	Surcharges	**5.5**	4.9	0.6	12.2%	4.3	4.9
(3)	Facilities rental	**2.1**	2.1	-	0.0%	2.4	2.3
(4)	Water heater rental	**18.2**	17.8	0.4	2.2%	17.4	17.2
(5)	Inter-company	**3.2**	3.2	-	0.0%	2.8	3.2
(6)	Other	**9.0**	9.2	(0.2)	-2.2%	9.3	10.4
(7)	Total miscellaneous revenue	**$ 40.9**	$ 39.9	$ 1.0	2.5%	$ 39.1	$ 40.7

2010/11F = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals
* at rates effective July 1, 2010

In 2010/11, miscellaneous revenue (at rates effective July 1, 2010) is budgeted to be $1.0 million (line 7, column 3) higher than the 2009/10 full year forecast. Please refer to the sections below for further details on the individual line items shown in Table 1F.

<u>CONNECTION REVENUE – TABLE 1F, LINE 1</u>

Connection revenue includes fees charged to customers for all initial service connection, reconnections and service call fees on the distribution system. Connection revenue is budgeted to increase by $0.2 million (line 1, column 3) or 7.4 per cent due to the three per cent rate increase and continued growth in the number of residential customers.

<u>SURCHARGES AND FACILITIES RENTAL – TABLE 1F, LINE 2 AND LINE 3</u>

Surcharges are late payment charges on overdue accounts and are budgeted to increase by $0.6 million (lines 2, column 3) due the general rate increase, new customer additions and an expected increase in residential arrears levels due to economic conditions. Facilities rental revenue is related to charges to industrial customers who rent Disco's substation facilities and is budgeted to be unchanged (line 3, column 3) in 2010/11.

<u>WATER HEATER RENTAL – TABLE 1F, LINE 4</u>

Water heater rental revenue is the cumulative monthly charges to customers participating in Disco's water heater program. Water heater rental revenue is expected to increase by $0.4 million (line 4, column 3) due to the rate increase, offset somewhat by natural gas penetration into the rental market and customers choosing to own their water heater.

<u>INTER-COMPANY – TABLE 1F, LINE 5</u>

Inter-company revenue is related to services provided by Disco to the NB Power Group. Examples of these services include building rental, protective and safety equipment testing, operational response, engineering support for capital programs, and meter services. Inter-company revenue is budgeted to remain unchanged in 2010/11.

<u>OTHER – TABLE 1F, LINE 6</u>

Other revenue includes revenue for items such as tree trimming services, services provided to telecommunication utilities, gains on the sale of fixed assets, and other miscellaneous third party work.

Other revenue is budgeted to decrease $0.2 million (line 6, column 3) in 2010/11 mainly due to

- decreased non-recurring revenue from third party storm restoration assistance and other third party work in 2009/10 - $0.7 million

offset by

- increased pole attachment revenue due to a higher number of third party attachments to Disco poles - $0.5 million

ATTACHMENT TO SECTION 1 – ENERGY SALES & REVENUE BUDGET DEVELOPMENT

Energy Sales Budget

The basis of the 2010/11 revenue budget is the first year of the 2010 to 2020 Load Forecast issued in March 2010. Details on how the load forecast is prepared are described below.

The load forecast is divided into three main groups: Residential, General Service and Industrial. The sum of the individual forecasts is the base sales forecast. Adjustments, such as natural gas impacts, to the base sales forecast are then added (or subtracted) to create the final sales volume forecast. Forecasts for Residential, General Service and Industrial are prepared at the provincial level and apportioned between Disco and wholesale municipal utilities based on historical sales and growth trends. The methodology used is consistent with that reviewed by the Public Utilities Board in 2007 with refinements to the model as a result of an independent audit.

Residential Forecast

Residential includes year-round domestic (household) customers. It also includes some non-domestic customers such as farms and churches. Also included in the Residential classification are seasonal customers. The electrical requirements for seasonal customers are small (one per cent) and are forecasted by extrapolating historical trends.

Increases in the Residential forecast are driven by the addition of new customers and increasing annual household usage. These are offset by reductions associated with energy efficiency, natural gas, and price elasticity. Residential sales are sensitive to variations in temperature. For forecasting purposes, 30-year normal weather is assumed.

The forecast for the total Residential class is based upon an end use model that requires identification of the various uses of electricity. These uses include space heating, water heating and other household appliances. The penetration (saturation) level and the average use for each household application provide the basis for average use per customer. The number of customers is based on an analysis of population trends and is dependent on population growth and decreases in household size.

The model can be stated as

$$\text{Energy} = \text{Year round Customers} \cdot \text{Average Use per Customer}$$

where,

$$\text{Average Use per Customer} = \Sigma\,(\text{Appliance} \cdot \text{Average Use})$$

therefore,

$$\text{Energy} = \text{Year round Customers} \cdot \Sigma\,(\text{Appliance} \cdot \text{Average Use})$$

An appliance efficiency model is used to estimate the changes in per unit consumption for a number of major household appliances: refrigerators, freezers, dishwashers, clothes washers and clothes dryers. The model requires data on penetration of appliances, the probability of a particular customer acquiring an appliance and the expected life of the appliance to determine the expected average use for each appliance. The model assumes all new appliances will meet existing energy efficiency standards.

The model also accounts for the fact that a portion of the apparent wasted energy in an electrically heated home actually goes towards heating the house. Therefore, the savings in electricity requirements are less than the difference in the energy consumption for existing and new appliances.

The penetration levels of major household electrical appliances are based on the 2008 Energy Planning Survey of residential customers. These surveys are generally conducted every 3 to 5 years.

Electric space and water heating normally account for about 65 per cent of the average household energy use. Most new homes are constructed with electric space heating (80 per cent) and water heating (90 per cent). In addition to the penetration levels of appliances, estimates of average energy use per appliance are required to determine the forecast annual energy consumption per customer. The annual energy required for space heating is derived by analyzing data from the previous year's sales. Average energy required for water heating is based on historical trending of kilowatt-hours per person. For the remaining appliances, estimates of average annual usage are based on the appliance efficiency model.

Adjustments to the base load forecast are made to account for developing trends including the impact of natural gas proliferation, conservation and energy efficiency improvements.

General Service Forecast

Sales to the General Service classification include commercial (retail/wholesale, hotel/motel/restaurants, offices) and institutional customers (hospitals, schools, universities). The General Service forecast is based on an econometric model. The General Service model relates changes in the level of sales to changes in the provincial gross domestic product, the number of heating degree days, the real price of electricity, and the previous year's level of sales. Adjustments to the base load forecast are made for energy efficiency programs.

Heating degree days are based on the weighted average provincial total for the 30-year period 1971 to 2000. The price elasticity assumptions are based on the anticipated real price increases in general service rates over the forecast period.

Energy Efficiency

The forecast also includes estimates of energy efficiency measures. The impact of improving construction standards in the residential sector is expected to increase the thermal shell efficiency of homes in the province, reducing average heating requirements by 0.25 per cent per year.

Estimates of Efficiency New Brunswick's program savings have been included in the forecast for the Residential, General Service and Industrial classes. These estimates are based on discussions and information from agency staff.

Industrial Forecast

New Brunswick's Industrial customers consume about 33 per cent of the total in-province electrical energy. Industrial customers are divided into two groups: Industrial Transmission (customers who are served at transmission voltages of 34 kV and above) and Industrial Distribution (customers who are served at distribution voltages of 25 kV or less).

Disco serves 38 industrial transmission customers, which accounts for the majority of total industrial electrical energy requirements (sales by Disco and incremental self generation). Disco serves some 1,900 industrial customers at distribution voltages, while the wholesale utilities serve approximately another 70 customers. The major Industrial Distribution groups are wood industries, food and beverage, manufacturing, and other operations.

Industrial Forecast Model

The Industrial Transmission and Interruptible/Surplus load forecasts incorporate expectations of the continued operation of facilities, new loads and closures over the forecast period. Information from account managers, historical sales trends and public announcements is used to forecast individual customer loads. The forecast also incorporates the existing self-generation capability of Industrial Transmission customers. The overall forecasts are the sum of individual forecasts for each of the customers in this class.

The Industrial Distribution forecast is based on an econometric model. The change in demand for electricity is linked to the change in provincial goods producing gross domestic product.

Wholesale Forecast

The Wholesale forecast is a subset of the total provincial forecast. The provincial Residential, General Service and Industrial Distribution forecasts are apportioned between Disco and wholesale municipal utilities based on historical sales and growth trends.

Revenue Budget

Revenue is estimated from the sales of power for each customer class using unit rate trend analysis, applying the associated rates to the billing determinant estimates or a combination of both. The following describes the process used to estimate revenue for each class.

Residential

The Residential sales budget is subdivided into billing components to estimate service charge revenue and energy sales revenue at the first and end blocks using the appropriate rate from the rate schedule.

- Service charge revenue is calculated by multiplying the rate by the number of forecasted customers times twelve for the number of months in a year.
- Budgeted energy sales are segmented into expected sales at the first and end blocks. The energy in each of these blocks is then multiplied by the applicable rate. After the elimination of the declining block rate structure, total energy is multiplied by the flat energy charge.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate on a weather adjusted basis to verify the billing determinant based calculation.

General Service

The General Service sales budget is first subdivided into General Service I or II and then further subdivided by billing component (i.e. service charge, demand charge and energy charges). Service charge, demand charge and energy charge revenue are estimated using the estimated billing determinant for each charge and the corresponding rate from the rate schedule.

- Service charge revenue is calculated by multiplying the rate by the number of forecasted customers times twelve for the number of months in a year.
- Demand revenue is estimated by converting energy to billing demand using a historical factor and then multiplying by the applicable demand rate.
- Energy revenue is estimated using budgeted energy sales segmented into expected sales at the first and end energy blocks. The energy in each of these blocks is then multiplied by the applicable rate.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate on a weather adjusted basis to verify the billing determinant based calculation.

Industrial Transmission

For Industrial Transmission, a monthly revenue budget is calculated for each of these customers using the budgeted billing determinants of each. The sum of demand charges and revenue from firm energy sales (minus Curtailable Credits and Declining Discounts where applicable) forms the revenue budget for each customer. The revenue budget for each customer is summed to estimate the total Industrial Transmission budget.

Industrial Interruptible/Surplus

The basis of the Interruptible/Surplus revenue budget is the monthly incremental cost of supplying this load. Total monthly energy sales are separated into on and off peak based on historical sales patterns. This energy is then multiplied by the applicable incremental cost plus the respective $9.00/MWh or $3.00/MWh on/off-peak adder.

Industrial Distribution, Wholesale and Non-metered

Industrial Distribution, Wholesale and Non-metered revenue is estimated in the same manner. Budgeted energy sales are multiplied by the expected unit rate to calculate revenue, which is compared to the moving 12-month unit rate and current revenue trends to verify the reasonableness of the estimate.

SECTION 2 - PURCHASED POWER

Disco fulfills its in-province capacity and energy requirements through agreements for the purchase of electrical capacity and energy from suppliers. Summary information on these power purchase agreements ("PPAs") and recent amendments is provided in Appendix B.

For 2010/11, Disco's total purchased power expense from all suppliers is forecasted to be $1,031.8 million (line 7, column 1), a decrease of $60.4 million (line 7, column 3) in 2010/11 compared to the 2009/10 full year forecast.

Table 2A

Purchased Power Expense
Fiscal Years Ending March 31
(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Genco	**$ 797.3**	$ 886.6	$ (89.3)	$ 929.5	$ (42.9)	$ 781.6
(2)	Nuclearco	**205.7**	205.0	0.7	248.2	(43.2)	208.3
(3)	Other	**55.7**	28.6	27.1	39.6	(11.0)	4.8
(4)	Benefit to customers of lawsuit settlement	**(26.9)**	(26.8)	(0.1)	(26.3)	(0.5)	(25.9)
(5)	Amortization of PLGS deferral	**-**	-	-	3.7	(3.7)	-
(6)	System Operator* settlement	**-**	(1.2)	1.2	-	1.2	2.3
(7)	Total purchased power expense	**$ 1,031.8**	$ 1,092.2	$ (60.4)	$ 1,194.7	$ (100.1)	$ 971.1

*New Brunswick System Operator ("System Operator")

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

SUMMARY

For 2010/11, the purchased power expense from the New Brunswick Power Generation Corporation ("Genco") is expected to be $797.3 million (line 1, column 1), a decrease of $89.3 million (line 1, column 3) in 2010/11 compared to the 2009/10 full year forecast. This decrease is due to

- decreased fuel costs - $91.1 million
- decrease costs as a result of lower capacity payments and greater export benefits partially offset by a return to average long-term hydro flows and no additional third party purchase benefits forecasted in 2010/11 - $10.7 million
- increased costs due to increase in energy purchases to meet load forecast requirements - $12.5 million

Purchased power expense related to the New Brunswick Power Nuclear Corporation ("Nuclearco") is expected to increase by $ 0.7 million (line 2, column 3) in 2010/11 from the 2009/10 full year forecast as a result of a contract price adjustment to account for a CPI change in accordance with the Nuclearco PPA.

Purchased power expense from other sources is forecasted to increase by $27.1 million (line 3, column 3) in 2010/11 from the 2009/10 full year forecast due to an increase in renewable energy purchases in 2010/11. Regulation 2006-58 under the *Electricity Act* requires Disco to obtain 10 per cent of its energy requirement from approved renewable energy generation facilities by 2016. In order to meet this target, Disco has entered into long-term contracts with suppliers. The first 96 MW wind farm began operations in 2008/09, a second 99 MW wind farm began operations in 2009/10, and a third and fourth (54 MW and 49.5 MW respectively) are planned to be operational in 2010/11.

The benefit to customers of the lawsuit settlement with PDVSA is budgeted to increase by $0.1 million (line 4, column 3) in 2010/11 from the 2009/10 full year forecast. The change reflects an adjustment to the settlement value due to changes in freight charges and foreign exchange. The benefit of the settlement is being provided to Disco and its customers on a levelized basis over a period of 17 years.

PLGS is assumed not to return to service during 2010/11 and therefore costs and expenses will continue to be recorded in the PLGS regulatory deferral account throughout 2010/11 (Table 2L). Amortization of the account will not begin in 2010/11 (line 5, column 1).

The following sections provide further detailed cost information as referenced in Table 2A.

PURCHASED POWER EXPENSE – GENCO TABLE 2A, LINE 1

Total purchased power cost from Genco, outlined in Table 2B, is expected to be $797.3 million (line 12, column 1), a decrease of $89.3 million (line 12, column 3) in 2010/11 compared to the 2009/10 full year forecast.

The costs in Table 2B have been categorized as follows

- Lines 1 – 7 represent yearly costs prescribed in the PPAs impacting Disco's 2010/11 forecasted revenue requirement
- Lines 8 - 11 represent specific in-year adjustments prescribed in the PPAs that are unpredictable in nature (can either be a benefit or cost) and are budgeted to be zero

Table 2B

Purchased Power Expense - Genco
Fiscal Years Ending March 31
(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Vesting energy charge	**$ 534.8**	$ 619.3	$ (84.5)	$ 625.5	$ (6.2)	$ 512.0
(2)	Capacity payment	**294.4**	303.1	(8.7)	303.1	-	303.1
(3)	Capacity payment adjustments	**8.5**	7.5	1.0	8.4	(0.9)	6.0
(4)	Interruptible and surplus energy	**8.0**	17.6	(9.6)	29.8	(12.2)	17.0
(5)	Combustion turbine and third party energy purchases	**0.1**	0.1	-	0.0	0.1	0.0
(6)	Export benefit (PPA prescribed credit)	**(43.4)**	(31.7)	(11.7)	(31.7)	-	(19.4)
(7)	Ancillary service credit	**(5.1)**	(5.4)	0.3	(5.6)	0.2	(5.3)
	Sub-total	**797.3**	910.5	(113.2)	929.5	(19.0)	813.4
	Adjustments (No impact on forecasted costs)						
(8)	Export benefits (third party gross margin adjustment)	**0.0**	(5.8)	5.8	0.0	(5.8)	(18.6)
(9)	Hydro flow adjustment	**0.0**	(15.6)	15.6	0.0	(15.6)	(14.3)
(10)	Adjustment for load imbalance	**0.0**	0.0	0.0	0.0	0.0	1.3
(11)	Third party purchase benefits adjustment	**0.0**	(2.5)	2.5	0.0	(2.5)	(0.2)
(12)	Total Genco	**$ 797.3**	$ 886.6	$ (89.3)	$ 929.5	$ (42.9)	$ 781.6

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Please refer to the sections below for further information on the individual line items in Table 2B.

VESTING ENERGY CHARGE – TABLE 2B, LINE 1

The vesting energy charge is expected to be $534.8 million (Table 2B, line 1, column 1), a decrease of $84.5 million (Table 2B, line 1, column 3) in 2010/11 compared to the 2009/10 full year forecast.

The vesting energy charge is comprised of two components defined in the Vesting PPA

- the Fuel component
- the Contribution to Fixed Costs component

Table 2C summarizes the component amounts for 2010/11, 2009/10 and 2008/09.

Table 2C

Make-up of the Vesting Energy Charge
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1) Fuel component	**$ 442.8**	$ 527.4	$ (84.6)	$ 540.9	$ (13.5)	$ 421.6
(2) Contribution to fixed costs	**92.0**	91.9	0.1	84.6	7.3	90.4
(3) Vesting energy charge	**$ 534.8**	$ 619.3	$ (84.5)	$ 625.5	$ (6.2)	$ 512.0

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

FUEL COMPONENT – TABLE 2C, LINE 1

The fuel component is determined by a mechanism set out in Sections 6.2.4 and 6.2.5, and Schedule 6.2 of the Vesting PPA. It is derived from key modeling inputs including

- Disco's in-province load forecast
- Forward fuel and energy purchase contracts
- Forward fuel and energy purchase prices
- Planned unit generator maintenance schedules
- Contractual forced outage rates
- Historical long-term average hydro generation
- Guaranteed unit generator heat rate curves
- Fixed prices for Heritage PPA with non-utility generators ("NUGs")
- An assumed production level for PLGS
- Forward foreign exchange purchase contracts
- Forward foreign exchange rates

These key modeling assumptions are input into a production modeling program known as PROMOD.[1] This modeling program is an established and widely used power system

[1] The inputs and outputs of PROMOD were reviewed by an independent financial consultant retained by the EUB.

simulation model that provides a capability to project power system operations and costs.

Based on the modeling assumptions, PROMOD calculates the estimated fuel and purchased power cost to serve Disco's forecasted load requirement for the next fiscal year. The estimated fuel cost is then divided by the quantity of energy produced to determine an average rate, which becomes the prescribed fuel component charge per MWh. This charge, set annually, typically prior to the start of the fiscal year, becomes Disco's fixed price per MWh for all vesting energy purchased from Genco through the following fiscal year.[2]

Genco and Disco continually look for ways to mitigate the impact of fuel cost increases. For example, Genco, acting on behalf of Disco, has taken advantage of energy purchases where possible to displace more costly internal thermal generation. In addition, Genco is planning to undertake capital work at the Belledune Generating Station during the spring 2010 planned unit maintenance outage to increase the unit generator's turbine output and efficiency with no increase in fuel consumption.

Disco and Genco agreed that this investment will provide an economic benefit and that this benefit should be passed to Disco to reduce Disco's power purchase costs under the Vesting Agreement.[3]

[2] The Vesting PPA was amended to extend the deadline for setting the annual Vesting Energy Price for 2010/11. On October 29, 2009 the provinces of New Brunswick and Québec signed a Memorandum of Understanding ("MOU") regarding the sale of NB Power to Hydro-Québec. Under the terms of the MOU, and as subsequently altered, the transaction would have resulted in the termination of the Vesting Agreement and therefore the Operating Committee did not set the Vesting Energy Price for 2010/11 prior to the commencement of the fiscal year. Please refer to Amendment No. 6 under Appendix B.

[3] The Vesting PPA was amended to allow energy purchases made to displace more costly internal generation and the benefit of the turbine upgrade project to be reflected in the Vesting Energy Price. The amendment also provides for Disco to reimburse Genco for the capital investment in the turbine over the remaining life of the Belledune Generating Station as a Capacity Payment Adjustment. Please refer to Amendment No. 5 under Appendix B.

During the period of the PLGS refurbishment the fuel component price per MWh reflects only the forecasted cost of fuel and purchased power for the volume of Vesting Energy supplied to Disco by Genco. The cost of fuel and purchased power to supply Disco with energy that would normally have been supplied by PLGS is accounted for separately and invoiced to Disco. The fuel and purchased power amount to be charged to the PLGS regulatory deferral account is the cost difference between what would have been paid to PLGS had it continued to operate and the amount invoiced by Genco.

The calculation of the prescribed fuel component price per MWh for 2010/11, 2009/10 and 2008/09 is illustrated in Table 2D.

Table 2D

Calculation of Prescribed Fuel Component Price
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10R	(3) Variance (1)-(2)	(4) % change (1)-(2)	(5) 2009/10B	(6) Variance (2)-(5)	(7) 2008/09B
(1) Heavy fuel oil	**$ 120.4**	$ 203.7	$ (83.3)	-40.9%	$ 193.9	$ 9.8	$ 158.3
(2) Natural gas and other Genco NUGs	**154.6**	201.1	(46.5)	-23.1%	200.3	0.8	177.0
(3) Imported coal and other	**114.8**	134.8	(20.0)	-14.8%	124.4	10.4	94.9
(4) Energy purchases	**47.3**	14.9	32.4	217.1%	19.1	(4.2)	21.5
(5) Fuel component total	$ 437.1	$ 554.5	$ (117.4)		$ 537.8	$ 16.7	$ 451.7
(6) Vesting energy requirement (MWh)	**9,336,000**	9,568,500	-232,500	-2.4%	9,317,700	250,800	10,206,400
(7) Prescribed fuel component ($/MWh)	**$ 46.81**	$ 57.95	$ (11.14)	-19.2%	$ 57.71	$ 0.24	$ 44.26

2010/11B = budget
2009/10R = revised fuel component price as a result of the PLGS return to service date change (revised in June of 2009)
2009/10B = budget
2008/09B = budget

Table 2D illustrates that the fuel component price per MWh has decreased from 2009/10 by $11.14/MWh or 19.2 per cent, from $57.95/MWh to $46.81/MWh.[4] This price decrease is driven primarily by decreases in world commodity market prices for

[4] Normally, after the Vesting Energy Price is set for the fiscal year any subsequent changes in either the quantity of Vesting Energy or the cost of supply do not affect the Vesting Energy Price. During the period of the PLGS refurbishment, however, the Vesting PPA provides for the Vesting Energy Price to be revised if the expected PLGS return to service date is different from that reflected in the original Vesting Energy Price. At the time the original Vesting Energy Price was set for 2009/10 (Table 2D, line 7, column 5) PLGS was expected to return to service on October 1, 2010. Subsequently, when the PLGS refurbishment was extended the Vesting Energy Price for 2009/10 was revised (Table 2D, line 7, column 2) to reflect the resulting increase in the quantity of Vesting Energy sold to Disco by Genco and the added cost of supply.

heavy fuel oil, natural gas and coal during the period leading up to setting the fuel component energy charge for 2010/11. Another notable improvement resulting in a lower fuel component for 2010/11, due to lower commodity market prices, is better pricing on electricity imports. A greater volume of imported electricity at a lower price in 2010/11 avoids running higher cost generators in New Brunswick. A reduced vesting energy requirement of 232.5 GWh in 2010/11 from 2009/10 (line 6, column 3) has also avoided running higher cost generators.

Prices for heavy fuel oil, coal, natural gas and energy purchases are driven by global factors that are beyond Disco's control. Disco manages the volatility in world commodity markets for heavy fuel oil and natural gas through its financial risk management program. In this program, Genco, acting as Disco's agent for fuel and energy purchasing, enters into forward fuel and energy purchase contracts that fix prices for estimated fuel and energy purchase requirements 18 months in advance. The program, implemented on a rolling monthly basis, benefits Disco and its customers by providing predictability and smoothes volatility impacts inherent in heavy fuel oil and natural gas commodity markets. Overall, the forward purchasing approach moves the timing of market increases and decreases out 18 months and smoothes any temporal dramatic market swings driven by world events (threats of war or terrorism, hurricanes, etc.). Genco also enters into forward purchase contracts for foreign exchange.

Disco fixes prices for imported coal for the coming year via fixed price, bi-lateral contracts. Genco, acting as Disco's agent, procures estimated imported coal requirements for the next fiscal year during the summer or fall of the preceding year. As with the forward purchase program for heavy fuel oil and natural gas, the practice of fixing prices in advance of the fiscal year provides predictability to Disco and its customers. During the 18-month period prior to setting of the fuel component energy charge for 2010/11, world commodity market prices were decreasing. These decreases are reflected in the forward fuel purchase contracts that are included in PROMOD. As commodity market prices change, they will be reflected in forward purchase contracts that flow into the fuel component energy charges in future periods.

The fuel component per MWh, as derived in Table 2D, is multiplied by the Vesting Energy requirement to determine the fuel component cost of the vesting energy charge under the Vesting PPA. Table 2E presents the cost resulting from actual requirements for 2008/09 and the expected requirements for 2009/10, compared to the forecasted requirements for 2010/11.

Table 2E illustrates that of the $84.6 million (line 3, column 3) decrease in the fuel component charge from the 2009/10 full year forecast to 2010/11; $105.5 million is attributable to a price decrease but is partially offset by a $20.9 million increase due to an increase in the volume of Vesting Energy purchased from Genco. In-province total energy requirements in 2009/10 was lower than anticipated because of warmer than usual temperatures while forecasted requirements for 2010/11 assumes a return to historical temperatures. In addition, in 2009/10, large industrial load was below normal as a result of several production shutdowns.

Table 2E

Vesting Energy Charge Fuel Component
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1) Prescribed fuel component $/MWh	**$ 46.81**	$ 57.95	$ (11.14)	$ 57.71	$ 0.24	$ 44.26
(2) Load requirement (MWh)	**9,460,361**	9,100,142	360,219	9,372,300	(272,158)	9,524,408
(3) Fuel component ($ millions)	**$ 442.8**	$ 527.4	$ (84.6)	$ 540.9	$ (13.5)	$ 421.6

(4)	Price variance 9,460,361 X ($11.14) =	$ (105.5)
(5)	Volume variance 360,219 X $57.95 =	$ 20.9
(6)	Total variance	$ (84.6)

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

CONTRIBUTION TO FIXED COSTS – TABLE 2C, LINE 2

The Contribution to Fixed Costs is a fixed MWh rate, as prescribed in Section 6.2.6 of the Vesting PPA. The Contribution to Fixed Costs rate is adjusted yearly by a CPI adjustment as per Schedule 1.1.30.[5]

[5] The Vesting PPA was amended to correct the language used to describe the CPI escalation for 2010/11 onward. Disco and Genco agreed that the language used in the Vesting PPA needed clarification. Please refer to Amendment No. 5 under Appendix B.

Table 2F illustrates that the $0.1 million (line 1, column 3) increase in the Contribution to Fixed Costs component in 20010/11 from the 2009/10 full year forecast is due entirely to an increase in price resulting from the CPI adjustment.

The Contribution to Fixed Costs is applied to the total volume of energy supplied to Disco, including energy to replace PLGS while it is out of service, and is capped at 12,000,000 MWh. Therefore, the volume of energy supplied by Genco to Disco in 2010/11 remains the same as in 2009/10. [6]

Table 2F

Vesting Energy Contribution to Fixed Costs
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1) Budgeted contribution to fixed costs $/MWh	**$ 7.67**	$ 7.66	$ 0.01	$ 7.72	$ (0.06)	$ 7.53
(2) Load requirement (MWh)	**12,000,000**	12,000,000	-	10,952,100	1,047,900	12,000,000
(3) Fixed cost component ($millions)	**$ 92.0**	$ 91.9	$ 0.1	$ 84.6	$ (84.4)	$ 90.4

(4)	Price variance 12,000,000 X $0.01 =	$ 0.1
(5)	Volume variance 0 X $7.66 =	$ -
(6)	Total variance	$ 0.1

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

In summary, the $84.5 million decrease in the vesting energy charge from the 2009/10 full year forecast to 2010/11, as illustrated in Table 2B, line 1, is comprised of

- a $105.5 million decrease in the fuel component due to lower commodity market prices for heavy fuel oil, coal and natural gas (Table 2E, line 4)
- a $20.9 million increase in the fuel component due to an increase in the volume of Vesting Energy purchased from Genco (Table 2E, line 5)
- a $0.1 million increase in the Contribution to Fixed Costs component attributable to the CPI adjustment (Table 2F, line 4)

[6] Under the terms of the Vesting PPA, Disco is entitled to receive from Genco a maximum of 12 terawatt-hours ("TWh") of energy annually. This annual cap is applied to the Contribution to Fixed Costs.

CAPACITY PAYMENT – TABLE 2B, LINE 2

The capacity payment to Genco is based on Disco's nomination of base load assets, as prescribed in Sections 2.1 and 6.1, and Schedule 1.1.17 of the Vesting PPA. Base load assets are generating plants that produce energy at relatively high annual capacity factors.

Disco has 2,357.6 MW of nominated capacity available to it under the Vesting PPA to meet the current and projected future demand requirements of its customers. This nominated capacity has been reduced by 67.5 MW from the 2009/10 nominated capacity of 2,425.1 MW. The reduction in nominated capacity is due to

- the early closure of Grand Lake Generating Station (56.8 MW)
- the expiration of a Heritage PPA (8.7 MW)
- the termination of a Heritage PPA due to major equipment failure (2.0 MW)

Despite the decrease in its nominated capacity under the Vesting Agreement, Disco is able to meet its capacity requirements due to the increased capacity available to it under its wind energy power purchase agreements.

The capacity payment is the nominated capacity multiplied by the capacity price as prescribed in Schedule 1.1.17 of the Vesting PPA. The annual rate for 2010/11, $124,875/MW, is relatively unchanged from the 2009/10 rate of $125,000/MW. The decrease in price is due to the reduction in nominated capacity. The capacity payment, outlined in Table 2B (line 2, column 1), is expected to be $294.4 million, a decrease of $8.7 million (Table 2B, line 2, column 3) in 2010/11 compared to the 2009/10 full year forecast. The total reduction is due to the reduction in the nominated capacity.

CAPACITY PAYMENT ADJUSTMENTS – TABLE 2B, LINE 3

The Vesting PPA and New Brunswick Power Coleson Cove Corporation ("Colesonco") PPA each contain provisions for adjusting the capacity payment subject to Disco's consent. Table 2G summarizes the capacity payment adjustments, all of which have been previously reviewed by the EUB with the exception of the Belledune Turbine Upgrade and force majeure claims made by Disco.

Table 2G

Capacity Payment Adjustments

Fiscal Years Ending March 31

(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Coleson Cove precipitator upgrades	**$ 4.0**	$ 4.0	$ -	$ 4.0	$ -	$ 4.0
(2)	Coleson Cove fuel conversion project	**3.9**	3.8	0.1	4.5	(0.7)	3.1
(3)	Coleson Cove refurbishment settlement	**(1.2)**	(1.2)	-	(1.2)	-	(1.2)
(4)	Belledune boiler waterwall upgrade	**1.1**	1.1	-	1.1	-	1.1
(5)	Belledune turbine upgrade	**0.7**	-	0.7	-	-	-
(6)	Force majeure claims	**-**	(0.2)	0.2	-	(0.2)	(1.0)
(7)	Total adjustments	**$ 8.5**	$ 7.5	$ 1.0	$ 8.4	$ (0.9)	$ 6.0

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

COLESON COVE PRECIPITATOR UPGRADES TABLE 2G, LINE 1

Disco agreed to compensate Genco, as per Sections 2.14 and 2.7 of the Colesonco PPA, for the upgrade of the precipitators to produce marketable gypsum and avoid land filling cost if the gypsum cannot be sold. Cost analysis determined that it is more economical to upgrade the precipitators to render the gypsum marketable for wallboard production than it is to landfill the contaminated gypsum.

COLESON COVE FUEL CONVERSION PROJECT TABLE 2G, LINE 2

In an effort to reduce fuel costs, Coleson Cove Unit 3 was converted to operate on a blend of heavy fuel oil and petroleum coke in the spring of 2008. Further capital spending on this project was included in the 2009/10 budget; however, all but a small portion of this spending has been deferred beyond 2010/11 due a change in market conditions. As a result, the 2010/11 budget reflects only a small increase over the 2009/10 full year forecast, and a decrease from the 2009/10 budget.

COLESON COVE REFURBISHMENT SETTLEMENT TABLE 2G, LINE 3

As prescribed in Section 2.9.3 of the Colesonco PPA, if Genco should receive any liquidated damages or other payments in connection with guarantees and/or warranties in respect to heat rate or other operating characteristics contracted under the Coleson

Cove refurbishment project, Disco is entitled to these settlements. Settlements with vendors occurred in 2005 and 2006 and as a result, Disco will continue to receive a credit of $1.2 million per year for the remaining life of the generating station.

<u>BELLEDUNE BOILER WATERWALL UPGRADE   TABLE 2G, LINE 4</u>

Belledune Generating Station had an accelerated corrosion problem on its boiler waterwall as a result of burning a mix of coal (75 per cent) and a petroleum coke (pet coke) (25 per cent). The Station has operated on a blend of coal and pet coke, a lower-cost fuel, since fiscal 1998/99. The Station could not continue to burn the current proportion of pet coke without causing further deterioration to the boiler. Consequently, the mix of pet coke was reduced in May of 2006 to 15 per cent following the spring 2006 maintenance outage. In order to resume the burning of a higher mix of pet coke, the boiler waterwall was upgraded and made more resistant to the corrosive effects of the pet coke fuel.

<u>BELLEDUNE TURBINE UPGRADE TABLE 2G, LINE 5</u>

Genco is making a capital investment at Belledune Generating Station that will improve the unit generator's turbine output and efficiency with no increase in fuel consumption. Disco and Genco have agreed to pass these fuel cost savings to Disco via the Vesting Energy Price and that the capital costs incurred by Genco to achieve the savings are to be paid by Disco. Please refer to Amendment No. 5 under Appendix B.

The capital project will be completed during the spring 2010 planned unit maintenance outage and the capacity payment adjustment is expected to begin mid-year.

<u>FORCE MAJEURE CLAIMS TABLE 2G, LINE 6</u>

Under the Vesting PPA, Article 14, Disco is entitled to make a Force Majeure claim in an effort to mitigate additional power purchase costs or reduce its costs when services under the PPA are not rendered.

- The 2009/10 full year forecast includes a $0.2 million (line 6, column 2) capacity payment reduction stemming from an unplanned shutdown at the Tobique Generating Station that lasted for more than three months.

- The 2008/09 actual results include a $ 1.0 million (line 6, column 6) capacity payment reduction as a result of a flood at the Grand Falls Generating Station that resulted in the Station being out of service for more than six months.

INTERRUPTIBLE AND SURPLUS ENERGY – TABLE 2B, LINE 4

Disco makes sales to customers with interruptible load at Interruptible/Surplus Energy Rates under the Large Industrial rate classification of Disco's Rates, Schedules and Policies.

The expense is Disco's quantity of Interruptible/Surplus energy sales from the 2010/11 load forecast multiplied by the forecasted incremental average cost of supply after fulfilling the in-province firm load requirements. The Vesting PPA includes provisions for interruptible energy in Sections 3.1.4 and 6.8.

The total forecasted cost for 2010/11 is $8.0 million (Table 2B, line 4, column 1), a decrease of $9.6 million (Table 2B, line 4, column 3) compared to the 2009/10 full year forecast. The decreased cost of supply is comprised of lower fuel cost ($1.2 million) and a decrease in interruptible load ($8.4 million).[7] The forecasted interruptible load reduction is the result of a large industrial customer increasing the firm energy portion of its requirements thereby decreasing its interruptible energy purchases.

COMBUSTION TURBINE AND THIRD-PARTY ENERGY PURCHASES – TABLE 2B, LINE 5

Expenses incurred to run combustion turbines ("CTs") and for third party out-of-province purchases to meet in-province load are priced separately as a pass-through of Genco's expense to Disco as prescribed in the Vesting PPA under Sections 6.6 and 6.7. In 2010/11, Disco is forecasting minimal generation from CTs to cover peak load requirements.

[7] As interruptible energy sales revenue is based on the cost to supply, the decrease in cost is offset by a corresponding decrease in interruptible and surplus revenue. Please refer to Section 1 – Budgeted Revenue (at rates effective July 1, 2010) for further detail.

EXPORT BENEFIT (PPA PRESCRIBED CREDIT) – TABLE 2B, LINE 6

The 2010/11 export benefit (third party gross margin credit) is $43.4 million as prescribed in Schedule 6.3 of the Vesting PPA. This is comparable to the export benefit prescribed in 2009/10 of $31.7 million. The year-over-year increase is due mainly to lower fuel costs, additional firm sales and more favourable export market conditions.

ANCILLARY SERVICE CREDIT – TABLE 2B – LINE 7

Ancillary services are Open Access Transmission Tariff ("OATT") services that ensure reliability and support to the transmission of electricity from generation sites to customer loads. Such services include load regulation, spinning reserve, non-spinning reserve, and voltage support.

Pursuant to Section 5.2.1 of the Vesting PPA, Disco is entitled to receive a credit for certain revenue received by Genco for the provision of ancillary services. The ancillary services credit is budgeted to be $5.1 million (Table 2B, line 7, column 1) in 2010/11. The decrease in 2010/11 of $0.3 million from the 2009/10 full year forecast (Table 2B, line 7, column 3) is due to a reduced share of the overall expense for reactive supply and voltage control services.

ADJUSTMENTS – TABLE 2B, LINES 8 - 11

Disco's purchased power costs for 2010/11 reflect budgeted purchased power expense under the Vesting PPA. Certain sections of the Vesting PPA allow for true-up, after the fact, of elements of Genco power purchase expense that are subject to significant in-year volatility. These include export benefits, hydro production and third party purchase benefits.

Disco's purchased power expense includes estimates of the impact of these variables, however, because of significant in-year volatility, after the fact true-ups or adjustments are required to settle the differences between Genco and Disco on a monthly or annual basis. These after-the-fact adjustments, which can be either a charge or a benefit to Disco, cannot be predicted and therefore are not reflected in Disco's forecasted costs for 2010/11.

The following text explains the true-up adjustments included in the 2009/10 full year forecast.

EXPORT BENEFITS ADJUSTMENT (THIRD PARTY GROSS MARGIN CREDIT) – TABLE 2B, LINE 8

In 2009/10, Genco's export gross margin forecast exceeded the prescribed credit under the Vesting PPA due to external market conditions. As a result, in 2009/10 Disco is expected to receive, in addition to the $31.7 million prescribed in Schedule 6.3, an additional $5.8 million for a total of $37.5 million.

HYDRO FLOW ADJUSTMENT – TABLE 2B, LINE 9

Under Section 6.12 of the Vesting PPA, should hydro-electric generation vary from the monthly assumed hydro production used to determine the Vesting Energy Price for serving the in-province firm load, an adjustment is calculated to credit or charge Disco for any excess or shortfall of hydro-electric generation.

In 2009/10, due to above average hydro flows, Disco is expected to receive a credit of $15.6 million.

ADJUSTMENT FOR LOAD IMBALANCE – TABLE 2B, LINE 10

Genco acquired Nepisiguit Falls Hydro Generating Station ("Nepisiguit Falls") in 2007. The System Operator did not recognize Nepisiguit Falls as a Genco facility until a Generator Connection Agreement was put in place in July 2008. In the interim, the electrical output of Nepisiguit Falls was netted off of Disco's load. The figure shown for 2008/09 (Table 2B, line 10, column 6) reflects a one-time payment to Genco for the energy supplied by Nepisiguit Falls.

THIRD PARTY PURCHASE BENEFITS ADJUSTMENT – TABLE 2B, LINE 11

Under Section 6.5 of the Vesting PPA, if Genco purchases energy to supply Disco's vesting energy requirements in any given hour and the rate paid by Genco is below the Vesting Energy Price, then Genco is to share equally the purchase benefits with Disco (i.e. the differential between the Vesting Energy Price and the power purchase rate for the volume of energy going to serve the in-province firm load).

The 2009/10 Vesting Energy Price reflects forecasted benefits of purchasing energy at a lower cost than internal oil-fired generation. In addition, market conditions arose in which Genco was able to occasionally purchase additional volumes of energy at a lower cost than the Vesting Energy Price, resulting in a further expected benefit to Disco of $2.5 million (Table 2B, line 11, column 2).

The 2010/11 Vesting Energy Price also reflects forecasted benefits of purchasing energy at a lower cost than internal oil-fired generation. If additional opportunities to purchase energy at a lower cost than the Vesting Energy Price arise during the year Disco will receive 50 per cent of the benefit.

PURCHASED POWER EXPENSE – NUCLEARCO TABLE 2A, LINE 2

Under the Nuclearco PPA, Disco purchases all of the energy output of the PLGS less Nuclearco's commitment to supply Maritime Electric Company, Limited under a participation agreement.

During the period of the PLGS refurbishment, purchased power expense related to Nuclearco is comprised of two components

- purchased power
- additional Nuclearco costs embedded in rates

Disco's total energy cost related to Nuclearco, outlined in Table 2H, is expected to be $205.7 million (line 3, column 1), an increase of $0.7 million (line 3, column 3) in 2010/11 compared to the 2009/10 full year forecast.

Table 2H

Purchased Power Expense - Nuclearco
Fiscal Years Ending March 31
(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Purchased power	**$ (1.1)**	$ (1.1)	$ -	$ 162.1	$ (163.2)	$ (1.1)
(2)	Additional Nuclearco costs embedded in rates	**206.8**	206.1	0.7	86.1	120.0	209.4
(3)	Total Nuclearco	**$ 205.7**	$ 205.0	$ 0.7	$ 248.2	$ (43.2)	$ 208.3

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

PURCHASED POWER – TABLE 2H, LINE 1

Disco's annual energy entitlement is determined by PLGS's forecasted output, which takes into consideration PLGS's planned maintenance outages as well as assumptions for forced outages and derations. The PLGS is currently undergoing refurbishment and is not expected to return to service in 2010/11.

Details of purchased power expense are provided in Table 2I.

Table 2I

Purchased Power - Nuclearco
Fiscal Years Ending March 31
(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Energy	**$ -**	$ -	$ -	$ 162.7	$ (162.7)	$ -
(2)	Ancillary service credit	**(1.1)**	(1.1)	-	(0.6)	(0.5)	(1.1)
(3)	Total purchased power	**$ (1.1)**	$ (1.1)	$ -	$ 162.1	$ (163.2)	$ (1.1)
(4)	Energy production (MWh)	**-**	**-**	-	**2,540,000**	(2,540,000)	**-**
(5)	Energy price ($/MWh)	**$ -**	**$ -**	**$ -**	**$ 64.06**	-64.06	**$ -**

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

<u>ENERGY – TABLE 2I, LINE 1</u>

Since PLGS is expected to be undergoing refurbishment for the entire year and will therefore not provide any energy to Disco, there is no energy charge in 2010/11.

In 2009/10, the budget reflected the PLGS returning to service October 1, 2009 with an associated energy charge for the year of $162.7 million (line 1, column 4). During the year it was announced that the refurbishment was being extended and as a result there was no energy charge reflected in the 2009/10 full year forecast.

<u>ANCILLARY SERVICE CREDIT – TABLE 2I, LINE 2</u>

Pursuant to Section 4.2.1 of the Nuclearco PPA, Disco is entitled to receive a credit for any revenue received by Nuclearco for the provision of ancillary services. In 2010/11, Nuclearco is forecasted to receive $1.1 million in revenue for ancillary services. This figure is unchanged from the 2009/10 full year forecast. Nuclearco's credit for ancillary services is based on a contracted price per MW with the System Operator.

<u>ADDITIONAL NUCLEARCO COSTS EMBEDDED IN RATES - TABLE 2H, LINE 2</u>

Disco's existing rates reflect the cost of energy that would normally have been produced by PLGS and purchased by Disco at the Nuclearco PPA price. In order to avoid over recovery from customers in the future, this amount is netted against the costs from Nuclearco and Genco that are charged to Disco and included in the PLGS regulatory deferral account and is therefore a cost to Disco in the period. Please refer to Table 2L, Regulatory Deferral – PLGS Refurbishment and accompanying text for more detail on how this charge is applied to the deferral account.

Disco has calculated this amount at what it would have paid Nuclearco for the quantity of energy supplied by Nuclearco if PLGS had continued to operate during the out of service period. This amount was determined in accordance with the Nuclearco PPA. Specifically, the Nuclearco PPA price paid by Disco to Nuclearco for energy prior to the out of service period, adjusted in accordance with the standard CPI escalation adjustment contained in the Nuclearco PPA.

Table 2J illustrates the determination of the amount for 2010/11.[8]

Table 2J

Additional Nuclearco Costs Embedded in Disco's Rates
Fiscal Years Ending March 31
(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Prescribed PPA Price ($/MWh)	**$ 54.35**	$ 54.18	$ 0.17	$ 54.47	$ (0.29)	$ 53.71
(2)	Assumed PLGS production (MWh)	**3,804,039**	3,804,039	-	1,579,700	2,224,339	3,897,793
(3)	Additional Nuclearco costs embedded in Disco's rates	**$ 206.8**	$ 206.1	0.7	$ 86.1	120.0	$ 209.4

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

The cost is expected to be $206.8 million (line 3, column 1), an increase of $0.7 million (line 3, column 3) in 2010/11 compared to the 2009/10 full year forecast. The increase is due entirely to CPI escalation of the per MWh price.

PURCHASED POWER EXPENSE – OTHER TABLE 2A, LINE 3

In 2010/11, other purchased power expense is expected to be $55.7 million. This is an increase of $27.1 million in 2010/11 from the 2009/10 full year forecast. This increase is due to an increase in renewable energy purchases in 2010/11. Regulation 2006-58 under the *Electricity Act* requires Disco to obtain 10 per cent of its energy requirement from approved renewable energy generation facilities by 2016. In order to meet this target, Disco has entered into long-term contracts with suppliers. The first 96 MW wind farm began operations in 2008/09, a second 99 MW wind farm began operations in 2009/10, and a third and fourth (54 MW and 49.5 MW respectively) are planned to be operational in 2010/11.

[8] The production levels in Table 2J reflect annual capacity factors of 71.78 per cent for 2010/11 and 2009/10 and 73.55 per cent for 2008/09. The quantity of energy for 2010/11 reflects the unavailability of PLGS for the full year. The quantity of energy for the 2009/10 budget reflected PLGS returning to service mid-year. These production levels reflect aging of the unit, outages and refueling and are based on Nuclearco's best estimate of what the station could have produced if it continued to operate.

BENEFIT TO CUSTOMERS OF LAWSUIT SETTLEMENT TABLE 2A, LINE 4

In August 2007, New Brunswick Power Holding Corporation (“Holdco”) reached a lawsuit settlement with PDVSA regarding the supply of fuel for Coleson Cove Generating Station (“Coleson Cove”). Because the settlement represented a recovery of the capital spent to prepare Coleson Cove to receive and burn Orimulsion® fuel, the estimated value of the settlement was applied against the remaining net book value of Coleson Cove. Colesonco will recognize the benefits of the settlement through reduced interest and amortization as a result of a reduction in debt levels and a reduction in the net book value of Coleson Cove respectively. The interest and amortization savings that Colesonco incurs are passed through to Disco as a credit to purchased power expense, which ultimately benefits Disco’s customers.

The EUB approved the implementation of a regulatory deferral account to enable the savings associated with the lawsuit settlement to be provided to customers on a levelized basis over a period of 17 years.

The levelized benefit is based on an estimate of the value of the settlement and will change slightly from year to year until all of the settlement fuel is received and the actual value of the settlement is known. The estimated value of the settlement is updated periodically to reflect changes in freight charges and foreign exchange. Detail of the benefit provided to customers is provided in Table 2K.

Table 2K

Regulatory Deferral - Lawsuit Settlement
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1) Benefit provided to customers	**$ (23.9)**	$ (24.3)	$ 0.4	$ (24.2)	$ (0.1)	$ (25.4)
(2) Interest	**(3.0)**	(2.5)	(0.5)	(2.1)	(0.4)	(0.5)
(3) Total benefit and interest	**$ (26.9)**	$ (26.8)	$ (0.1)	$ (26.3)	$ (0.5)	$ (25.9)

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

AMORTIZATION OF PLGS REFURBISHMENT DEFERRAL TABLE 2A, LINE 5

Following PLGS's return to service the PLGS refurbishment regulatory deferral will be amortized over the life of the refurbished station. PLGS is assumed not to return to service during 2010/11 and therefore there is no amortization expense included in 2010/11 revenue requirement.

The following section explains the intent and components of the PLGS refurbishment regulatory deferral.

In January 2008, an amendment was made to the *Electricity Act* to add s. 143.1 – Refurbishment of PLGS. This amendment sets out the authority to record and recover

(i) certain costs and expenses incurred by Nuclearco in relation to the project during the out of service period, and

(ii) certain costs and expenses incurred by Genco related to the supply of additional electricity to Disco in relation to the project during the out of service period ("Additional Costs").

This amendment requires Nuclearco and Genco to record the specified costs and invoice Disco monthly for the specified costs, net of certain revenues, during the "out of service period".[9]   It also requires Disco to establish a deferral account to record the invoiced amounts and to recover the deferred amount from customers over the operating life of the refurbished PLGS.

Section 143.1(9) sets out the authority for Disco to dispose of the deferral account and recover the deferred costs from customers. In doing so, the legislation ensures that the deferral account[10] is a regulatory asset for purposes of Disco's financial statements.

[9] "out of service period" means the period of time beginning when the PLGS is out of service due to the project until such time that the station returns to normal service (s. 143.1(1) of the *Electricity Act*)

[10] A deferral account is considered to be a regulatory asset if the future recovery in rates has legislative or regulatory approval.

Table 2L summarizes the activity in the deferral for 2009/10, 2008/09, and 2007/08.

Table 2L

Regulatory Deferral - PLGS Refurbishment
Fiscal Years Ending March 31
(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1) Out of service costs of Nuclearco	**$ 171.1**	$ 178.6	$ (7.5)	$ 75.2	$ 103.4	$ 176.3
(2) Additional costs of Genco	**236.1**	223.3	12.8	101.5	121.8	267.5
(3) Sub-total	**407.2**	401.9	5.3	176.7	225.2	443.8
(4) Less: costs embedded in Disco's rates	**(206.8)**	(206.1)	(0.7)	(86.1)	(120.0)	(209.4)
(5) Net amount deferred	**200.4**	195.8	4.6	90.6	105.2	234.4
(6) Less: levelized charge to customers	**-**	-	-	3.7	(3.7)	-
(7) Net change in regulatory deferral	**$ 200.4**	$ 195.8	$ 4.6	$ 86.9	$ 108.9	$ 234.4

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

As illustrated in Table 2L, Disco records in the PLGS deferral account the out of service costs invoiced by Nuclearco (line 1) and the costs related to the supply of additional electricity invoiced by Genco (line 2). However, the simple deferral of both of these amounts would not be appropriate since a portion of the costs are already included in the charges, rates and tolls charged by Disco.

Disco's existing rates reflect its cost of purchased power, including the energy that would normally have been produced by PLGS and purchased by Disco at the Nuclearco PPA price. This cost, which is being collected from customers in existing rates, must be used to offset the costs from Nuclearco and Genco that are included in the deferral account. This offset (line 4) will avoid over recovery from customers. From Disco's perspective the only just and reasonable approach is to defer an amount net of the revenue received for this energy through existing rates.

Disco has calculated the amount at what it would have paid Nuclearco for the quantity of energy supplied by Nuclearco if PLGS had continued to operate during the out of service period. This amount was determined in accordance with the Nuclearco PPA. Specifically, the Nuclearco PPA price paid by Disco to Nuclearco for energy prior to the out of service period, adjusted in accordance with the standard Consumer Price Index ("CPI") escalation adjustment contained in the Nuclearco PPA. Please refer to Table 2J, Additional Nuclearco costs embedded in Disco's rates.

To illustrate the year-over-year change in costs related to the volume of energy that is, or would normally be, provided by Nuclearco, the amount is reflected in the cost of purchased power related to Nuclearco (Table 2H).

PURCHASED POWER EXPENSE – SYSTEM OPERATOR SETTLEMENT TABLE 2A, LINE 6

Disco's purchase of energy is based on scheduled energy with the System Operator. Inadvertent energy, the difference between the energy scheduled and that which is actually transmitted, is known as load imbalance. The load imbalance is settled with Disco at the end of each month based on the New Brunswick Electricity Market Rules

In addition to load imbalance there is also a residual monthly cost that is paid to, or collected from, transmission customers when all market settlements are completed at the end of each month by the System Operator. Depending on the volume and price differentials for variables such as load imbalance, generator imbalance, and generator re-dispatch, the residual is allocated to transmission customers based on their respective peak volume of transmission service.

Since these two types of market settlements cannot be forecasted, the 2010/11 forecasted revenue requirement does not include any amount for these items. However, in the 2009/10 full year forecast, Disco is forecasting an accumulated credit of $1.2 million associated with market settlements based on year-to-date activity.

SECTION 3 - TRANSMISSION EXPENSE

Disco is provided transmission services under the OATT and the Market Rules. Disco subscribes to Network Integration Service and Point-to-Point Transmission Service under rates specified in the OATT and administered by the System Operator. These charges are set to recover the capital, operation and maintenance costs of the transmission network. In addition to Network Integration Service and Point-to-Point Transmission Service, Disco is required under the OATT to compensate the System Operator for ancillary services provided to the transmission network. These services are for the support and reliability of the transmission system and include reactive supply and voltage control, load regulation, load following, spinning reserve, and non-spinning reserve.

Table 3A summarizes Disco's transmission expense for 2010/11, 2009/10 and 2008/09.

Table 3A

Transmission Expense

Fiscal Years Ending March 31

(in millions $)

		(1) **2010/11B**	(2) 2009/10E	(3) Variance (1)-(2)	(4) 2009/10B	(5) Variance (2)-(4)	(6) 2008/09A
(1)	Network transmission services	**$ 49.8**	$ 49.4	$ 0.4	$ 50.7	$ (1.3)	$ 48.7
(2)	Point-to-point transmission services	**2.8**	1.0	1.8	0.0	1.0	0.0
(3)	System Operator services - Schedule 1	**7.3**	6.8	0.5	5.4	1.4	4.9
(4)	System Operator services - Schedule 2	**3.6**	3.9	(0.3)	3.6	0.3	3.4
(5)	Capacity based ancillary services	**2.7**	2.6	0.1	3.0	(0.4)	3.0
(6)	Total Transmission expense	**$ 66.2**	$ 63.6	$ 2.6	$ 62.7	$ 0.9	$ 60.0

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

The total transmission expense, outlined in Table 3A, is expected to be $66.2 million (line 6, column 1), an increase of $2.6 million (line 6, column 3) in 2010/11 compared to the 2009/10 full year forecast.

- $0.4 million (line 1, column 3) is attributed to an increase demand for network transmission services as a result of a higher in-province load forecast

- $1.8 million (line 2, column 3) is attributed to an increase demand for point-to-point transmission services for the purchase of PLGS replacement energy from outside New Brunswick
- $0.5 million (line 3, column 3) is due to increased costs for Schedule 1 services from the NBSO (based on the NBSO revenue requirement filed with the EUB on March 15, 2010)
- $0.3 million (line 4, column 3) decrease is due to a reduced share of the overall expense for reactive supply and voltage control services
- $0.1 million (line 5, column 3) cost increase for capacity based ancillary services is attributed to a higher requirement for network transmission services

NETWORK TRANSMISSION SERVICES - TABLE 3A, LINE 1

Each substation is metered for energy consumption (kilowatt-hours) and peak demand (kilowatts). The OATT rate for network service reflects that the cost drivers of the transmission system are related to peak demand. The rate for the transmission service is therefore based on peak demand. The peaks are recorded at each substation without consideration to the total coincident system peak and are referred to as non-coincident peak ("NCP") demands. The NCP demands are summed across all of Disco's distribution substations plus the peak demands of the wholesale and industrial substations. The total monthly NCP demand is multiplied by the OATT rate and summed across twelve months to determine Disco's Network Integration Service charge.

POINT-TO-POINT TRANSMISSION SERVICES - TABLE 3A, LINE 2

Point-to-point transmission services are required for importing energy on a daily, weekly, or monthly basis whenever economic opportunities arise to purchase energy at lower costs than otherwise would be possible from a Genco generator. Energy purchases reduce PLGS replacement energy costs while PLGS is being refurbished. The amount budgeted for 2010/11 reflects historical monthly cost. The rates for point-to-point transmission services are provided in the OATT.

SYSTEM OPERATOR SERVICES AND CAPACITY BASED ANCILLARY SERVICES – TABLE 3A, LINES 3 to 5

Mandatory ancillary services under the OATT include

- Schedule 1 - Scheduling, System Control and Dispatch Service
- Schedule 2 - Reactive Supply and Voltage Control
- Schedule 3 - Regulation and Frequency Response Service
- Schedule 5 - Operating Reserve – Spinning Reserve Service
- Schedule 6 - Operating Reserve – Supplemental Reserve Service

Disco pays for ancillary services based on its monthly NCP demand at OATT rates in a manner similar to Network Integration Service described above. As of April 01 2009, charges under Schedule 1 and 2 are calculated as follows: Customer Usage/Total Usage x 1/12 of the System Operator Annual Revenue Requirement where usage is measured as NCP.

Schedule 3, 5, and 6 of the OATT set out the capacity based ancillary services. The OATT and the New Brunswick Market Rules provide that, for capacity based ancillary services, a market participant can either (i) purchase from the System Operator at OATT rates or (ii) purchase from a third party or (iii) self-supply up to 90 per cent. Disco self-supplies 90 per cent of its capacity based ancillary service requirements using the resources available to it under the PPAs.

The decrease in transmission expense associated with Schedules 2, 3, 5, and 6 (Table 3A, lines 4 and 5) is also reflected as a decrease in the ancillary service credit received through the Genco PPA Section 5.2.1 (Table 2B, line 7). This credit reduction is included in the Genco PPA costs identified in Section 2 – Purchased Power, Table 2B line 7.

SECTION 4 – OPERATIONS, MAINTENTANCE & ADMINISTRATION (OM&A)

The components of Disco's OM&A expense are

- Direct OM&A expense
- Inter-company services ("Inter-company") expense
- Holdco Shared Services ("Shared Services") expense
- Holdco Corporate Services ("Corporate Services") expense

OM&A expense relates to the operation, maintenance and administration of the distribution system that delivers electricity directly to over 339,000 customers and indirectly to approximately 42,000 customers (through two wholesale municipal utilities) in New Brunswick. Direct OM&A consists of costs incurred and paid directly by Disco for such items as salaries, contractors and suppliers. Inter-company services, Holdco Shared Services and Holdco Corporate Services represent services provided to Disco by other companies within the NB Power Group.

Table 4A summarizes Disco's OM&A expense for 2010/11, 2009/10 and 2008/09.

Table 4A

OM&A - Summary

Fiscal Years Ending March 31

(in millions $)

		(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
		2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1)	Direct OM&A	**$ 86.6**	$ 88.5	$ (1.9)	$ 87.8	$ 0.7	$ 83.6
(2)	Inter-company	**5.7**	5.2	0.5	5.1	0.1	5.2
(3)	Shared Services	**21.7**	18.4	3.3	19.8	(1.4)	18.6
(4)	Corporate Services	**9.3**	8.4	0.9	8.1	0.3	7.0
(5)	Total OM&A	**$ 123.3**	$ 120.5	$ 2.8	$ 120.8	$ (0.3)	$ 114.4

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Total budgeted OM&A expense is expected to be $123.3 million (line 5, column 1), an increase of $2.8 million (line 5, column 3) in 2010/11 compared to the 2009/10 full year forecast.

Please refer to the following sections for more information on the variances.

DIRECT OM&A - TABLE 4A, LINE 1

Direct OM&A expense is outlined in detail in Table 4B.

Table 4B

Direct OM&A Expense by Category

Fiscal Years Ending March 31

(in millions $)

	(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
	2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1) Labour & benefits	**$ 58.0**	$ 56.5	$ 1.5	$ 58.9	$ (2.4)	$ 57.6
(2) Hired services	**17.9**	18.9	(1.0)	19.5	(0.6)	17.3
(3) Materials	**5.4**	5.8	(0.4)	4.9	0.9	5.5
(4) Pension and retirements	**9.1**	6.8	2.3	5.3	1.5	3.7
(5) Vehicles	**5.5**	4.8	0.7	6.2	(1.4)	5.5
(6) Communications	**2.9**	2.6	0.3	2.8	(0.2)	2.4
(7) Bad debt	**3.5**	7.1	(3.6)	2.7	4.4	6.0
(8) Equipment	**1.6**	1.5	0.1	1.4	0.1	1.2
(9) Travel	**1.1**	1.0	0.1	1.3	(0.3)	0.9
(10) Insurance & claims	**0.8**	1.0	(0.2)	0.8	0.2	0.8
(11) Properties	**0.1**	0.1	-	0.1	-	-
(12) Other	**1.4**	0.7	0.7	1.4	(0.7)	1.3
(13) Allocations to capital	**(20.7)**	(18.3)	(2.4)	(17.5)	(0.8)	(18.6)
(14) Direct OM&A expense	**$ 86.6**	$ 88.5	$ (1.9)	$ 87.8	$ 0.7	$ 83.6

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

SUMMARY

Direct budgeted OM&A is expected to be $86.6 million (line 14, column 1), a decrease of $1.9 million (line 14, column 3) in 2010/11 compared to the 2009/10 full year forecast. The major contributing factors are explained below.

- Bad debt expense is expected to return to normal levels in 2010/11. There was significant pressure placed on 2009/10 as a result of unexpected large industrial write-offs.
- Allocations to capital are expected to increase in 2010/11 as a result of an increase in capital project spending which requires additional labour and overhead costs to support project completion.

- Hired service expense is expected to decrease in 2010/11 as a result of one-time costs incurred in 2009/10 for consulting costs and reduced costs in 2010/11 associated with wellness activities, account collections, water heater contracted services and property related services. These costs are partially offset by higher costs anticipated for various studies to support regulatory activities and the Conservation and Education Program[1].

offset by

- Labour and benefits expenses are expected to increase as a result of union and non-union wage increases , and the addition of resources to allow for appropriate training for pending retirements; offset by a partial year reduction in labour costs associated with the staff reduction program (these staff reductions will be absorbed and not replaced).
- Pension and retirements expenses are expected to increase as a result of the costs associated with the staff reduction program. This is a one time cost for the 2010/11 fiscal year. This increase is offset marginally by a better than expected return on plan assets in 2009/10.
- “Other” expenses are expected to increase primarily as a result of increased costs associated with regulatory activity (EUB direct and common costs) in 2010/11.

Please refer to the sections below for further information on the individual line items comprising direct OM&A.

<u>LABOUR & BENEFITS (TABLE 4B, LINE 1)</u>

Labour and benefits represent the direct and indirect labour expense for all Disco employees. It includes union and non-union wages, and employer portion of benefits and statutory remittances (current service costs for pension and retirement allowance, health and dental benefits, Canada Pension Plan, Employment Insurance, Workplace Health and Safety Compensation).

[1] The Conservation and Education Program is a multi-year initiative designed to promote awareness and provide current and future customers with information and tools to mitigate rising electricity prices through conservation activities.

A detailed breakdown of labour and benefits expense is provided in Table 4C.

Table 4C

Labour and Benefits Expense

Fiscal Years Ending March 31

(in millions $)

	(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
	2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1) Labour	**$ 45.3**	$ 43.4	$ 1.9	$ 45.1	$ (1.7)	$ 42.0
(2) Benefits	**7.9**	7.6	0.3	9.6	(2.0)	9.8
(3) Overtime	**4.8**	5.5	(0.7)	4.2	1.3	5.8
(4) Total labour and benefits	**$ 58.0**	$ 56.5	$ 1.5	$ 58.9	$ (2.4)	$ 57.6

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Disco's budgeted labour and benefits expense of $58.0 million (line 4, column 1) in 2010/11 is the single largest component of Disco's **direct** budgeted OM&A expense (67 per cent); and of Disco's **total** budgeted OM&A expense (47 per cent). Details of these costs include

- Budgeted wages expense (union and non-union) of $45.3 million (line 1, column 1) is associated with a budgeted 669 regular and term employees (as at March 31, 2011) , 90 per cent of which are unionized
- Budgeted benefits expense (union and non-union) of $7.9 million (line 2, column 1) reflects the employer portion of benefits and statutory remittances which is budgeted at 17.5 per cent of labour expense
- Budgeted overtime of $4.8 million (line 3, column 1) is driven by the requirement for Disco to provide emergency service 24 hours a day

Labour and benefits expense is expected to increase by $1.5 million (line 4, column 3) from the 2009/10 full year forecast to the 2010/11 budget due to

- year over year union and non-union wage increases (the 2010/11 budget assumes a 3.5 per cent increase for unionized staff, as per the collective agreement, and there is a 0 per cent cost of living increase assumed for non-union positions[2]) and new operational positions (12 apprentice linemen) which are required to ensure appropriate levels of customer service ($2.8 million).

[2] The two year wage freeze for non-union staff will commence in February 2011.

Certain positions such as the apprentice line trade require four years of training to become certified.

- benefit rates are expected to remain stable at 17.5 per cent, which results in a expected increase in benefit costs of $0.3 million

offset by

- decreases assumed in labour ($0.9 million) associated with the staff reduction program. The 2010/11 budget assumes that Disco will have 17 people (25 per cent of non-union staff) leave the organization and there would be savings for a partial year.
- reduced overtime in 2010/11 ($0.7 million). There was a large amount of storm activity in 2009/10 requiring overtime. The level of activity is expected to return to normal levels in 2010/11.

HIRED SERVICES (TABLE 4B, LINE 2)

Hired services are used to supplement and support Disco's regular workforce. Services are contracted to provide and support specialized or highly technical services, non-routine/one time work requirements, meet seasonal and peak period work requirements and to provide flexibility in the workforce. Hired services are the second largest component of direct budgeted OM&A. It consists of $17.9 million (table 4B, line 2, column 1) in 2010/11, which is comprised of contracts for a variety of services such as

- contracts to support ongoing activities related to the distribution system including
    - vegetation management to reduce incidents of trees contacting energized lines ($4.0 million)
    - operations and maintenance of Disco's distribution assets ($1.1 million)
    - flagging services to ensure safety of Disco employees ($1.0 million)
    - customer electricity restoration support during storms ($0.5 million)
- contracts relating to the provision of 24 hour a day service to customers renting water heaters from Disco ($3.5 million)
- contracts related to the handling of calls in the customer interaction center, payment of overdue accounts, printing customer bills, and maintaining payment options ($2.0 million)

- contracts for building maintenance services which includes janitorial, security, lawn maintenance and snow removal ($1.1 million)
- legal, expert and technical costs to support the regulatory process ($1.0 million)
- contract work for a telecommunications company supporting operational and maintenance requirements for Disco to allow for the achievement of economies of scale between Disco and the company (these costs are billed and recovered through miscellaneous revenue) ($0.9 million)
- funds for Conservation and Education Program ($0.8 million)
- contracts for meter reading services ($0.7 million)
- contracts that support the safety of employees and the public ($0.3 million)
- other miscellaneous contracts less than $0.2 million each which include a variety of smaller one-time and recurring services such as advertising, technical studies, customer input and environmental requirements

Hired services expense is expected to decrease $1.0 million (Table 4B, line 2, column 3) from 2009/10 full year forecast to 2010/11 budget primarily as a result of

- lower costs as a result of one time costs in 2009/10 for consulting services related to technology upgrades and enhancements - $1.1 million
- reduction in hired services for employee health and wellness programs and contact center contracted agents - $0.4 million
- savings related to process changes enabled by the implementation of the Workforce Management System[3]- $0.4 million
- lower cost for water heater contractors due to an expected decrease in maintenance costs - $0.2 million
- lower anticipated property maintenance - $0.2 million

offset by

- higher anticipated costs for various studies to support regulatory activities - $0.8 million

[3] The workforce management system was a multi-year business process improvement initiative which included an end-to-end review of core work management and maintenance management processes and the implementation of a set of integrated technologies that support operational requirements.

- increased costs for the Conservation and Education program - $0.5 million

MATERIALS (TABLE 4B, LINE 3)

Materials expense budget of $5.4 million (Table 4B, line 3, column 1) relates to a variety of miscellaneous material items that are used in day to day operations for planned and unplanned distribution work and for third party work (recovered in miscellaneous revenue). Types of materials include water heater parts, meter supplies, street light parts, other miscellaneous materials and supplies as well as the costs associated with the delivery of materials.

Materials expense is expected to decrease by $0.4 million (Table 4B, line 3, column 3) from 2009/10 full year forecast to 2010/11 budget mainly due to one-time material costs incurred in 2009/10 for materials provided to contractors or customers and those used to complete third-party work ($0.3 million) (costs are offset by miscellaneous revenue) and lower materials expense in 2009/10 associated with maintenance activities ($0.1 million).

PENSION AND RETIREMENTS EXPENSE (TABLE 4B, LINE 4)

Pension and retirements include costs related to Disco's pension plan, early retirement programs and retirement allowance programs.

Disco employees are members of the Province of New Brunswick Public Service Superannuation Plan ("PSSP"). This multi-employer defined benefit plan provides pensions based on length of service and the average of the highest five consecutive years of earnings. The plan allows for pension benefits to escalate each year. Disco and its employees make contributions to the plan as prescribed in the Public Service Superannuation Act and its regulations.

Disco also has a retirement allowance program for employees that provides for a lump sum payment equal to one week of pay for each full year of employment to a maximum of 26 weeks.

Retirement allowance program obligations and early retirement program obligations are unfunded.

Expenses related to Pensions and Retirements are actuarially determined and accounted for in accordance with the Canadian Institute of Chartered Accountants ("CICA") standards and accordingly include

- current service costs (included in labour & benefits (Table 4B, Line 1))
- interest on accrued benefit obligations
- interest earned on pension plan assets
- amortization of gains/losses on assets or obligations
- retirement allowance – amortization costs
- early retirement – interest
- other employee future benefits costs

Costs are amortized over the expected average remaining service life of the employee group (16 years).

NB Power announced a staff reduction program in April 2010 as a means to reduce costs. This program will have an estimated one time cost of $2.9 million (Table 4D, line 5, column 1) in 2010/11 for direct Disco employees. The costs of this program covers such items as the purchase of up to three years of pensionable service or benefits, waiver of penalty or additional retirement allowance, depending on the age and years of service of the individual who chooses to leave the organization.

Please refer to Table 4D for a breakdown of pension and retirements expense.

Table 4D

Pension and Retirements

Fiscal Year Ending March 31

(in millions $)

	(1) **2010/11B**	(2) 2009/10E	(3) Variance (1) - (2)	(4) 2009/10B	(5) Variance (2) - (4)	(6) 2008/09A
(1) Pension - interest and amortization	**$ 4.3**	$ 4.9	(0.6)	$ 3.4	$ 1.5	$ 1.7
(2) Retirement allowance - amortization	**0.9**	0.8	0.1	0.8	-	0.9
(3) Early retirement - interest and amortization	**0.9**	0.9	-	0.9	-	0.9
(4) Other	**0.1**	0.2	(0.1)	0.2	-	0.2
(5) Early retirement program	**2.9**	-	2.9	-	-	-
(6) Total pension and retirements expense	**$ 9.1**	$ 6.8	$ 2.3	$ 5.3	$ 1.5	$ 3.7

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Total pension and retirements expense is expected to increase $2.3 million (Table 4D, line 6, column 3) from 2009/10 full year forecast to 2010/11 budget. The increase consists of

- increase in retirement cost as a result of the staff reduction program ($2.9 million) (line 5, column 3). This is a one time cost in 2010/11 which will provide for labour savings beyond 2010/11.

offset by

- decrease in pension interest and amortization expense ($0.6 million) (line 1, column 3) due to an expected increase in the return on plan assets for 2009/10. Gains experienced on assets in 2009/10 result in a decrease in costs for 2010/11 and onward.

<u>VEHICLES (TABLE 4B, LINE 5)</u>

Vehicles expense relates to ongoing regular fuel and maintenance and miscellaneous expenses associated with Disco's fleet of vehicles, short-term vehicle leases and associated fuel. Disco maintains a fleet of approximately 400 vehicles, which consists of cars, ¼ to ¾ ton vehicles, one to 10 ton vehicles, trailers and off road vehicles. The Shared Service Fleet department works with Disco management to identify and manage all vehicle requirements.

Vehicle expenses for 2010/11 are budgeted to be $5.5 million (Table 4B, line 5, column 1). Vehicles expense is expected to increase by $0.7 million (Table 4B, line 5, column 3) from 2009/10 full year forecast to 2010/11 budget and is primarily related to higher maintenance and fuel costs. Maintenance costs are budgeted based on number of vehicles, historical maintenance costs and anticipated repairs.

COMMUNICATIONS (TABLE 4B, LINE 6)

Communications expenses for 2010/11 are budgeted to be $2.9 million (Table 4B, line 6, column 1). Communications expense includes postage and courier services (customer bills, customer information, late payment/disconnect notices) and costs required to support regulatory requirements.

Communications expenses are expected to increase by $0.3 million (Table 4B, line 6, column 3) from 2009/10 full year forecast to 2010/11 budget. The increase is driven primarily by an assumed increase in communication costs such as shipping, postage, printing and translation of materials.

BAD DEBT (TABLE 4B, LINE 7)

Bad debt expense relates to revenue write-offs and adjustments to allowance for doubtful accounts due to customer defaults (where payment is unlikely). Disco writes off, on a monthly basis, accounts that are deemed uncollectible from

- bankruptcies
- deceased customers
- inactive accounts where the aged receivables are greater than 365 days in arrears

Bad debt expense for 2010/11 is budgeted to be $3.5 million (Table 4B, line 7, column 1). Bad debt expense is expected to decrease by $3.6 million (Table 4B, line 7, column 3) from 2009/10 full year forecast to 2010/11 budget. Bad debt expense has increased in 2009/10 related to large industrial accounts. Disco does not budget for unforeseen large industrial customer bad debt due to the uncertainty of occurrence.

EQUIPMENT (TABLE 4B, LINE 8)

Equipment expense is related to software maintenance agreements and small tools and equipment (less than $5,000) to perform distribution work.

Budgeted equipment expense is budgeted to be $1.6 million (Table 4B, line 8, column 1) in 2010/11. The increase of $0.1 million (Table 4B, line 8, column 3) from 2009/10 full year forecast to 2010/11 budget is a result of contract increases related to software maintenance agreements and upgrade costs required to support information technology applications.

TRAVEL (TABLE 4B, LINE 9)

Travel expense relates to all non-fleet expenses incurred by employees while traveling for Disco business. Travel expense includes both in-province and out-of-province travel such as

- lodging and meals
- non-fleet gas and mileage
- travel allowances for unionized employees
- air travel

Budgeted travel expense is expected to be $1.1 million (Table 4B, line 9, column 1) in 2010/11, an increase of $0.1 million (Table 4B, line 9, column 3) from 2009/10 full year forecast to 2010/11 budget. The increase is related to in-province travel required to properly train additional power line technician apprentices which will help sustain customer service levels and provide for appropriate succession planning.

INSURANCE & CLAIMS (TABLE 4B, LINE 10)

Insurance and claims represents vehicle, general liability, all risk and blanket crime insurance premiums as well as water heater and other miscellaneous damage claim expenses. Disco self insures on vehicle, general liability, and all risk and blanket crime policies as follows

- Vehicle – physical damage
- General Liability – individual damage claims under $250,000

- All risk property – losses specifically related to buildings and substations up to $500,000; other all risk property losses are self insured.
- Blanket crime – all losses under $25,000

Insurance and claims expense is budgeted to be $0.8 million (Table 4B, line 10, column 1) in 2010/11 budget, a decrease of $0.2 million (Table 4B, line 10, column 3) from the 2009/10 full year forecast. The decrease is the result of a legal claim which arose in 2009/10. No such claims are expected in 2010/11.

PROPERTIES (TABLE 4B, LINE 11)

Properties expense includes water and sewage expenses at operating centers and rental of a small warehouse facility to house distribution material. Properties expense is expected to remain stable at $0.1 million (Table 4B, line 11, column 1) per year in 2010/11.

OTHER (TABLE 4B, LINE 12)

Other expense includes employee training as identified by Human Resources and Management, regulatory fees (EUB), environmental fees for storage of hazardous material, dues (e.g. Canadian Electricity Association, "CEA") and professional memberships (e.g. accountants and engineers).

Other expense is expected to be $1.4 million (Table 4B, line 12, column 1) in 2010/11 budget, an increase of $0.7 million (Table 4B, line 12, column 3) from the 2009/10 full year forecast, of which $0.5 million are associated with regulatory proceedings (EUB assessment). There was very little regulatory activity in 2009/10. Also, training is expected to return to normal levels, after effort was taken to reduce such costs in 2009/10 to offset other cost pressures.

ALLOCATIONS TO CAPITAL (TABLE 4B, LINE 13)

Allocations to capital relate to OM&A expenses charged to capital in support of capital construction work. They include labour directly attributable to capital as well as an overhead allocation. Allocations to capital results in an increase in capital project costs and a reduction in OM&A costs.

Overhead costs are incremental in nature. These overhead costs would not exist if Disco did not construct its own fixed assets. Overhead expenditures which are capitalized include such costs as salaries and benefits of operational and engineering personnel not directly chargeable to projects and the cost of administrative services provided by various departments which are required to support capital projects. The overhead rate is applied to the total monthly project cost, calculated on the capital expenditures during the month. Disco's overhead rates are as follows

	Rate
Customer Demand and Planned System Improvements	50%
"Other" capital work (information technology, vehicles, water heaters, tools & equipment)	21%

The overhead rates include the following components

- an appropriate share of the "non-productive time" (vacation, sick time and statutory holidays) of personnel charging directly to projects
- support and infrastructure costs associated both with personnel charging directly to projects and with personnel associated with overhead activities

When vehicles are used to support capital projects, then an associated cost is applied to those capital projects and credited to operations costs.

Please refer to Table 4E for a breakdown of allocations to capital expense.

Table 4E

Allocations to Capital Expense

Fiscal Year Ending March 31

(in millions $)

	(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
	2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1) Labour and benefits to capital	**$ 5.0**	3.8	$ 1.2	$ 3.4	$ 0.4	$ 4.2
(2) Overhead to capital	**14.8**	13.6	1.2	13.2	0.4	13.6
(3) Vehicles to capital	**0.9**	0.9	-	0.9	-	0.8
(4) Total allocations to capital	**$ 20.7**	$ 18.3	**$ 2.4**	$ 17.5	**$ 0.8**	$ 18.6

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Allocations to capital expense is expected to increase by $2.4 million (line 4, column 3) from 2009/10 full year forecast to 2010/11 budget as a result of capital improvement projects, which results in an increase in labour and overhead to capital. The two projects that are driving this increase are the second phase of a Customer Service Delivery project, focused on commercial customers; as well as upgrade work required to support the Outage Management System (OMS) and Computer Aided Dispatch Systems (CAD)[4] applications.

INTER-COMPANY - TABLE 4A, LINE 2

Inter-company expenses relate to services charged to Disco by other operating companies in the NB Power Group. These services are operational in nature. As the other operating companies have the existing infrastructure, Disco contracts for the provision of services at negotiated volumes and prices based on defined cost drivers. These services provide an economic benefit to Disco. Contracts were developed in consultation with management representatives from Disco and other operating companies. The contracts take the form of Service Level Agreements (SLA) which have been previously filed with the EUB. Disco also provides services to the other operating

[4] CAD is a mobile workforce management application used to plan, schedule and dispatch all customer service maintenance and capital work orders. OMS is an application which is used to manage outages by identifying affected customers, providing status updates to customers, creating switching plans to allow power restoration and to dispatch crews.

companies and any revenue received by Disco under the SLAs are reported in Section 1 – Budgeted Revenue (at rates effective July 1, 2010).

Examples of inter-company services provided to Disco include

- line switch maintenance, service restoration assistance, detection and repair of conductor and equipment hot spots, high voltage insulator replacement
- electrical apparatus maintenance services
- electrical construction and maintenance support
- vegetation control at substations
- land survey services
- substation maintenance evaluations
- protective equipment and telecommunications services
- mobile radio services

Examples of cost drivers include

- direct labour hours
- materials
- equipment usage

Inter-company services expenses are expected to increase by $0.5 million (table 4A, line 2, column 3) from 2009/10 full year forecast to 2010/11 budget as a result of service cost increases in labour and other categories which are passed on to Disco, and specific service requirements that Disco has identified for 2010/11 from NB Power Transmission Corporation ("Transco").

SHARED SERVICES – TABLE 4A, LINE 3

Shared Services expense consists of approximately twelve services broadly categorized as business, environment, supply chain and information systems. Shared Services is a department of Holdco. The companies within NB Power maximize economies of scale in information systems costs, procurement and in transactional and administrative tasks that are common among NB Power. Disco and their customers benefit from the economies of scale afforded by sharing in centralized services. The services are billed using a cost recovery model.

SLAs are negotiated and put in place annually as part of the budgeting and planning process.

SLAs with Holdco are designed to meet the following objectives

- to fully allocate costs
- to establish clear visibility for the cost of the service and the drivers of those costs
- to match service costs to those clients who derive the benefits from such services
- to provide value-added services through financial prudence

The cost recovery methodology applied the following principles

- costing and pricing model should be fair, equitable, accurate, simple and understandable
- all charges for a service are traced to the operating company that requests the service

Examples of shared service offerings include

- information systems and personal computer management
- telecommunication
- facilities management
- records and information management
- computer aided drafting and design
- environmental services
- real estate
- supply chain management

Examples of cost drivers include

- direct labour hours
- telephone usage
- price per desktop/laptop/workstation/device
- number of employees
- transactions
- number of invoices/files
- vehicle number and type
- allocation

Shared Services expense are budgeted to increase $3.3 million (table 4A, line 3, column 3) from 2009/10 full year forecast to 2010/11 budget as a result of

- impact of staff reduction program costs in 2010/11 - $2.1 million
- increase in software maintenance and licensing costs $0.5 million
- amortization of new assets - $0.5 million
- transfer of functions from Corporate Services to Shared Services - $0.1 million
- increase in voice services costs related to improvements made to Interactive Voice Response technology - $0.1 million

CORPORATE SERVICES – TABLE 4A, LINE 4

Disco is allocated a share of Holdco's Corporate Services expense. This expense includes Disco's share of the compliance and governance activities undertaken on behalf of NB Power. These include specialized functions such as legal, audit, finance, accounting research, risk management and treasury, financial planning, corporate planning, corporate communications, and human resources. Disco and their customers benefit from the economies of scale afforded by sharing centralized services.

Disco's share of Holdco Corporate Services expenses is primarily allocated to Disco based on the cost drivers for each of the Holdco Corporate Service departments, which was supported by an independent study. However, certain expense categories are directly charged to specific operating companies based on planned usage (e.g. legal, regulatory). Examples of cost drivers for each of the Holdco Corporate Service departments include

- total assets
- total revenue
- OM&A
- Net property plant and equipment

Disco's share of the total Corporate service allocation is approximately 26 per cent.

The expense is budgeted to increase $0.9 million (Table 4A, line 4, column 3) from 2009/10 full year forecast to 2010/11 budget as a result of

- staff reduction program costs in 2010/11 - $0.9 million
- finance projects that benefit all Opcos in the NB Power Group - $0.2 million
- amortization of information technology software and equipment - $0.2 million

offset by

- cost reductions resulting from the transfer of functions from Corporate Service to Shared Services and partial year labour savings associated with the staff reduction program - $0.4 million

SECTION 5 - AMORTIZATION EXPENSE

Amortization expense is driven by Disco's investment in the distribution system and retirement of related property, plant and equipment. The amortization of fixed assets is based on useful service lives. The straight-line method of amortization is used for all assets. The estimated service lives and amortization rates-remaining life were developed using the group amortization concept, which consists of grouping depreciable property into similar groups and determining an average life of the group based on the "Equal Life Group" theory[1]. Amortization is provided for all assets sufficient to amortize the cost of such assets, less estimated salvage value, over their estimated service lives.

The cost of distribution assets retired, net of dismantlement and salvage, is charged to accumulated amortization. For all other property, plant and equipment dispositions, the cost and accumulated amortization is removed from the accounts, with the gain or loss on disposal being reflected in income.

The components of amortization expense are detailed in Table 5A.

[1] The "Equal Life Group" theory involves subdividing the groups of assets into service lives and amortizing the assets in the subdivided groups together. The total amortization for the group is the sum of the amortization of the subdivided groups.

Table 5A

Amortization Expense

Fiscal Years Ending March 31

(in millions $)

		(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
		2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1)	Distribution assets	**$ 29.0**	$ 28.3	$ 0.7	$ 27.9	0.4	$ 27.5
(2)	Substations	**3.2**	3.0	$ 0.2	3.1	- 0.1	2.9
(3)	General properties	**0.5**	0.5	$ -	0.5	-	0.5
(4)	Vehicles	**2.5**	2.3	$ 0.2	2.3	-	2.0
(5)	Office equipment	**-**	-	$ -	-	-	-
(6)	Tools	**0.1**	0.1	$ -	0.1	-	-
(7)	Information systems	**4.8**	4.4	$ 0.4	5.1	- 0.7	4.2
(8)	Customer contributions	**(2.0)**	(1.9)	$ (0.1)	(1.7)	- 0.2	(1.7)
(9)	Total Amortization expense	**$ 38.1**	$ 36.7	$ 1.4	$ 37.3	$ (0.6)	$ 35.4

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Amortization expense is budgeted to increase by $1.4 million (line 9, column 3) in 2010/11 compared to the 2009/10 full year forecast. The largest increase of $0.7 million (line 1, column 3) is related to the category ‘Distribution assets’ (line 1) and is a result of an increase in capital spending in the prior year for customer demand and planned distribution system work. There is also an increase in information technology amortization of $0.4 million (line 7, column 3) resulting from the capitalization in 2009/10 of the Workforce Management Project.

SECTION 6 - TAXES (EXCLUDING SPECIAL PAYMENTS IN LIEU OF INCOME TAXES)

The components of taxes (excluding special payments in lieu of income taxes) are detailed in Table 6A.

Table 6A

Taxes (Excluding Special Payments in Lieu of Income Taxes)

Fiscal Years Ending March 31
(in millions $)

	(1)	(2)	(3) Variance	(4)	(5) Variance	(4)
	2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1) Utility tax	**$ 9.5**	$ 9.5	$ -	$ 9.6	$ (0.1)	$ 9.4
(2) Property tax	**1.0**	0.9	0.1	0.9	-	0.9
(3) Right of way tax	**0.5**	0.5	-	0.5	-	0.5
(4) Special payments in lieu of provincial large corporation tax	**-**	-	-	-	-	0.5
(5) Total taxes	**$ 11.0**	$ 10.9	$ 0.1	$ 11.0	$ (0.1)	$ 11.3

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Taxes (excluding special payments in lieu of income taxes) are budgeted to increase by $0.1 million (line 5, column 3) in 2010/11 compared to the 2009/10 full year forecast. Please refer to the accompanying sections for further details on the individual line items.

<u>UTILITY TAX – TABLE 6A, LINE 1</u>

Disco is required to pay utility taxes under the *Assessment Act* to the Minister of Finance. The utility tax is based on the net book value ("NBV") of Disco's distribution system and substation assets (as at the end of the previous fiscal year) at a rate of $2.25 per $100 of NBV. The utility tax is expected to remain stable from 2009/10 to 2010/11.

PROPERTY TAX – TABLE 6A, LINE 2

Property tax has two components - provincial tax and municipal tax. The provincial tax is based on the assessed value of real properties at a provincial rate of $2.25 per $100 of assessed value and the municipal rate varies by municipality. Property tax expense is budgeted to increase by $0.1 million (line 2, column 3) from 2009/10 to 2010/11 due to increases in municipal rates.

RIGHT OF WAY TAX – TABLE 6A, LINE 3

Disco is required to pay right of way tax to the Minister of Finance. The right of way tax is assessed based on kilometres of distribution lines and the tax rate varies depending on the type of line. Right of way tax in 2010/11 is expected to remain consistent with historical levels.

SPECIAL PAYMENTS IN LIEU OF PROVINCIAL LARGE CORPORATION TAX – TABLE 6A, LINE 4

Disco was required to make special payments in lieu of taxes to Electric Finance Corporation ("Electric Finance") as provided for under the *Electricity Act, s. 37* in fiscal year 2008/09. These special payments in lieu of provincial LCT were phased out by the provincial government effective January 1, 2009.

SECTION 7 - INTEREST EXPENSE

Disco uses a combination of long and short-term debt to supply its needs for financing. Capital expenditures are financed through long-term notes payable to Electric Finance and working capital is financed through short-term notes payable to Holdco.

The components of interest expense are listed in Table 7A.

Table 7A

Interest Expense
Fiscal Years Ending March 31
(in millions $)

		(1)	(2)	(3)	(4)	(5)	(6)
				Variance		Variance	
		2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1)	Interest on long-term debt	**$ 51.2**	$ 46.1	$ 5.1	$ 44.8	$ 1.3	$ 35.0
(2)	Interest on short-term debt	**2.5**	0.2	2.3	4.5	(4.3)	2.9
(3)	Debt portfolio management fee	**7.5**	5.4	2.1	5.2	0.2	3.8
(4)	Deferred debt costs	**1.0**	0.9	0.1	-	0.9	0.3
(5)	Interest credited to the PLGS Regulatory Deferral	**(28.5)**	(16.3)	(12.2)	(7.6)	(8.7)	(3.5)
(6)	Interest - other	**0.4**	0.4	-	0.3	0.1	0.3
(7)	Interest during construction	**(1.0)**	(0.8)	(0.2)	(1.0)	0.2	(1.3)
(8)	Total interest expense	**$ 33.1**	$ 35.9	$ (2.8)	$ 46.2	$ (10.3)	$ 37.5

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

Total interest expense is budgeted to decrease in 2010/11 to $ 33.1 million (line 8, column 1), a decrease of $ 2.8 million (line 8, column 3) from the 2009/10 full year forecast. Please refer to the sections below for further detail on the individual line items.

INTEREST ON LONG-TERM DEBT – TABLE 7A, LINE 1

Long-term debt consists of debt instruments with greater than a one-year term to maturity. Disco's outstanding long-term notes call for a principal repayment of one per cent annually on the anniversary date of each note. Interest expense is calculated based on the coupon rate of the note and the amount of the principal outstanding during the year.

Table 7B itemizes the outstanding notes, their coupon rates, issue and maturity dates and principal amounts budgeted at the beginning and end of 2010/11. The calculated budgeted interest expense for 2010/11 is also presented for each note.

Table 7B

Long-Term Debt and Interest Expense

Fiscal Year Ending March 31, 2011

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
					(in millions $)		
	Issue Number	Coupon Rate	Issue Date	Maturity Date	Principal Amount March 31 2010B	Principal Amount March 31 2011B	Interest Expense 2010/11B
(1)	D3	7.50%	01-Oct-04	31-Oct-11	141.0	139.5	10.5
(2)	D5	6.38%	01-Oct-04	15-Jun-10	61.8	0.0	0.8
(3)	D6	5.50%	01-Oct-04	15-Feb-13	51.7	51.2	2.8
(4)	D7	4.37%	27-Jan-06	03-Dec-15	96.0	95.0	4.2
(5)	D8	4.45%	13-Nov-08	26-Mar-18	176.4	174.6	7.8
(6)	D9	3.35%	13-Jan-09	01-Jun-19	118.8	117.6	3.9
(7)	D10	4.40%	05-Jun-09	03-Jul-19	150.0	148.5	6.6
(8)	D11	4.40%	29-Sep-09	03-Jun-19	100.0	99.0	4.4
(9)	D12	4.80%	02-Mar-10	26-Sep-39	100.0	99.0	4.8
(10)	D13	4.92%	15-Jun-10	15-Jun-20	0.0	65.0	2.6
(11)	D14	4.92%	29-Sep-10	29-Sep-20	0.0	100.0	2.5
(12)	D15	4.92%	15-Feb-11	15-Feb-21	0.0	50.0	0.3
(13)	Total promissory notes				$ 995.7	$ 1,139.4	
(14)	Total long-term debt interest expense						$ 51.2

B = budget

Interest expense on long-term debt is budgeted to increase by $ 5.1 million (Table 7A, line 1, column 3) in 2010/11 because of an increase in long term debt primarily required to finance the PLGS regulatory deferral.

INTEREST ON SHORT-TERM DEBT – TABLE 7A, LINE 2

Short-term debt consists of debt instruments with less than a one-year term to maturity. Interest on short-term debt is calculated on a weighted average of 7 to 120-day borrowing rates. The forecasted interest rates use the forward curve analysis for the Province of New Brunswick. The budgeted weighted average rate for 2010/11 is 1.31 per cent. The budgeted expense is based on the short-term debt balance budgeted for the end of each month in the fiscal year.

Interest expense on short-term debt is budgeted to increase by $2.3 million (Table 7A, line 2, column 3) in 2010/11 due mainly to an increase in the budgeted short-term debt interest rates in 2010/11, as well as an increase in the overall short-term debt balance.

DEBT PORTFOLIO MANAGEMENT FEE – TABLE 7A, LINE 3

The debt portfolio management fee is a fee for the reduction in interest rates available to Disco because Electric Finance borrows under the Province's credit rating in the debt capital markets on Disco's behalf. The debt portfolio management fee is paid to Electric Finance as provided for under the *Electricity Act,* s. 37(4) and affected by an Order in Council. The debt portfolio management fee is calculated at a rate of 0.6489 per cent applied to the amount of short-term and long-term debt owing at the opening balance sheet date, March 31, 2010. This rate and calculation is consistent with prior years.

The debt portfolio management fee is budgeted to increase by $2.1 million (Table 7A, line 3, column 3) in 2010/11 compared to 2009/10 full year forecast because of the increase in short-term and long-term debt in 2010/11.

DEFERRED DEBT COSTS – TABLE 7A, LINE 4

Deferred debt costs are discounts and premiums related to the issuance of long-term debentures. These discounts and premiums are amortized over the terms of the long-term debentures. Deferred debt costs are budgeted to increase by $0.1 million (Table 7A, line 4, column 3) in 2010/11 compared to the 2009/10 full year forecast because of long-term debt issued in 2010/11.

INTEREST CREDITED TO THE P PLGS REGULATORY DEFERRAL – TABLE 7A, LINE 5

Interest credit to the PLGS Regulatory Deferral include credits for the short-term and long-term debt interest to finance the PLGS refurbishment regulatory deferral and are expected to increase by $12.2 million (Table 7A, line 5, column 3) from 2009/10 full year forecast to 2010/2011 budget.

INTEREST - OTHER – TABLE 7A, LINE 6

Other interest expenses includes net charges such as interest earnings, interest on deposits, and other various bank charges such as wire fees, non-sufficient funds charges, and depot fees; and are expected to remain constant from 2009/10 full year forecast to the 2010/11 budget.

INTEREST DURING CONSTRUCTION (“IDC”) – TABLE 7A, LINE 7

IDC capitalizes the interest expense related to the funds expended on capital projects not yet in service (work-in-progress). IDC is calculated based on the accumulated balances in work-in-progress on a monthly basis and is capitalized as part of the costs of construction until the asset goes into service. The rate applied is the two year weighted average cost of long-term debt plus the debt premium or discount and the debt portfolio management fee.

The budgeted IDC rate for 2010/11 is 5.62 per cent, the calculation for which is shown in Table 7C.

Table 7C

IDC Rate

Fiscal Year Ending March 31, 2011
(in millions $)

	(1)	(2)	(3)	(4)	(5) = (2)*(4)	(6)	(7)	(8) = (2)*(7)
	Issue Number	Coupon Rate	Principal Amount March 31 2010B	% of Total Long-Term Debt	March 31, 2010 Weighted Avg. Cost of Debt	Principal Amount March 31 2011B	% of Total Long-Term Debt	March 31, 2011 Weighted Avg. Cost of Debt
(1)	D3	7.50%	141.0	14.53%	1.09%	139.5	13.11%	0.98%
(2)	D5	6.38%	61.8	6.36%	0.41%	0.0	0.00%	0.00%
(3)	D6	5.50%	51.7	5.33%	0.29%	51.2	4.81%	0.26%
(4)	D7	4.37%	96.0	9.89%	0.43%	95.0	8.93%	0.39%
(5)	D8	4.45%	176.4	18.17%	0.81%	174.6	16.40%	0.73%
(6)	D9	3.35%	118.8	12.24%	0.41%	117.6	11.05%	0.37%
(7)	D10	4.40%	150.0	15.45%	0.68%	148.5	13.95%	0.61%
(8)	D11	4.40%	100.0	10.30%	0.45%	99.0	9.30%	0.41%
(9)	D12	4.46%	75.0	7.73%	0.34%	74.0	6.95%	0.31%
(10)	D13	4.92%	0.0	0.00%	0.00%	65.0	6.11%	0.30%
(11)	D14	4.92%	0.0	0.00%	0.00%	100.0	9.40%	0.46%
(12)	Total promissory notes		$ 970.7	100.00%		$ 1,064.4	100.00%	
(13)	Weighted average cost of debt				4.92%			4.83%
(14)	Debt Premimum / Discount				0.10%			0.09%
(15)	Weighted average cost of debt, before debt portfolio mgt fee				5.02%			4.92%
(16)	Debt portfolio management fee rate				0.65%			0.65%
(17)	Weighted average cost of debt				5.67%			5.57%
(18)	Two year weighted average cost of debt							5.62%

2010B and 2011B = budget

The IDC amount is budgeted to increase in 2010/11 to $1.0 million (Table 7A, line 7, column 1) due to the timing of capital spending, partially offset by lower IDC rates in 2010/11.

SECTION 8 - SPECIAL PAYMENTS IN LIEU OF INCOME TAXES

Disco is required to make special payments in lieu of taxes to Electric Finance as provided for under the *Electricity Act,* s. 37. These payments are used by Electric Finance to service the debt that was transferred from NB Power to Electric Finance at the time of restructuring. These payments are summarized in Table 8A below.

Table 8A

Special Payments in Lieu of Income Taxes

Fiscal Years Ending March 31

(in millions $)

		(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
		2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1)	Net Earnings (Loss) (Table A, line 9)	**26.5**	(60.2)	86.7	(93.9)	33.7	22.7
(2)	Add: special payments in lieu of income taxes	**10.8**	(27.0)	37.8	(43.7)	16.7	10.8
(3)	Earnings / (Loss) before special payments in lieu of income taxes	**$ 37.3**	$ (87.2)	$ 124.5	$ (137.6)	$ 50.4	$ 33.5
(4)	Income tax rate	**28.88%**	31.00%		31.75%		32.38%
(5)	Total special payments in lieu of income taxes	**$ 10.8**	$ (27.0)	$ 37.8	$ (43.7)	$ 50.4	$ 10.8

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

<u>SPECIAL PAYMENTS IN LIEU OF INCOME TAXES – TABLE 8A, LINE 5</u>

The calculation for special payments in lieu of income taxes (line 5) are calculated as stipulated by Regulation 2008-9 under the *Electricity Act*. No allowance is made for temporary differences as the tax bases of assets and liabilities are considered to be the same as their carrying amounts for the purposes of the calculation.

The $37.8 million (line 5, column 3) budgeted increase in 2010/11 in special payments in lieu of income tax is attributable to the budgeted increase in earnings for 2010/11 offset by the reduction in the tax rate in compliance with legislation.

SECTION 9 - NET EARNINGS (LOSS)

Table 9A summarizes Disco's net earnings for 2010/11, 2009/10 and 2008/09.

Table 9A

Pre-tax Interest Coverage Ratio

Fiscal Years Ending March 31

(in millions $)

		(1)	(2)	(3) Variance	(4)	(5) Variance	(6)
		2010/11B	2009/10E	(1) - (2)	2009/10B	(2) - (4)	2008/09A
(1)	Net Earnings (Loss) (Table A, line 9)	**26.5**	(60.2)	86.7	(93.9)	33.7	22.7
(2)	Add Back : Net interest expense and special payments in lieu of income tax expense (Table A, lines 7 and 8)	**43.9**	8.9	35.0	2.5	6.4	48.3
(3)	Earnings / (Loss) before interest and special payments in lieu of income taxes	**70.4**	(51.3)	121.7	(91.4)	40.1	71.0
(4)	Less: Debt portfolio management fee	**(7.5)**	(5.4)	(2.1)	(5.2)	(0.2)	(3.8)
(5)	Plus: interest income	**-**	-	-	-	-	-
(6)	Adjusted earnings before interest and special payments in lieu of income taxes	**$ 62.9**	$ (56.7)	$ 119.6	$ (96.6)	$ 39.9	$ 67.2
(7)	Interest on long-term debt	**51.2**	$ 46.1	5.1	44.8	1.3	$ 35.0
(8)	Interest on short-term debt	**2.5**	0.2	2.3	4.5	(4.3)	2.9
(9)	Gross interest expense	**$ 53.7**	$ 46.3	$ 7.4	$ 49.3	$ (3.0)	$ 37.9
(10)	Pre-tax interest coverage ratio *(line 6/ line 9)*	1.17x	-1.22x	2.40x	-1.96x	.73x	1.77x

2010/11B = budget
2009/10E = full year forecast as at January 2010
2009/10B = budget
2008/09A = actuals

The budgeted net earnings for 2010/11 budget are $ 26.5 million (line 1, column 1). This budgeted net earnings results in a pre-tax interest coverage ratio of 1.17 times (line 10, column 1).

This level of interest coverage will assist in enabling Disco to gradually move toward a position where it is able to service all of its debt obligations, including payments of interest and repayment of outstanding debt when it comes due, and fund capital expenditures while maintaining a reasonable level of equity through retained earnings.

Information Package relating to New Brunswick Power Distribution and Customer Service Corporation forecasted revenues and costs for 2010/2011

28 May, 2010

Volume 1 of 1
Board Reference: 2010-006

Appendix A

Board Resolution

APPENDIX A

April 6, 2010
Board Meeting

PLAN 2010/RATE RECOMMENDATION

On motion duly made, seconded and unanimously carried, the board of directors approved Plan 2010 (fiscal year 2010/11) as revised in accordance with materials presented, approved the implementation of a 3% rate increase, the staff reduction program and the submission of Plan 2010 (fiscal year 2010/11) to the shareholder.

Information Package relating to New Brunswick Power Distribution and Customer Service Corporation forecasted revenues and costs for 2010/2011

28 May, 2010

Volume 1 of 1
Board Reference: 2010-006

Appendix B

PPA Overview

PPA Amendments

- Amendment No. 5 to Vesting Agreement
- Amendment No. 6 to Vesting Agreement

APPENDIX B – POWER PURCHASE AGREEMENTS (PPAs) - OVERVIEW

The *Electricity Act* was proclaimed on October 1, 2004. Under the *Act,* Disco is the standard service provider and is responsible for supplying adequate capacity and energy to meet in-province customer requirements.

BACKGROUND ON PURCHASED POWER AGREEMENTS

Disco fulfills its in-province capacity and energy requirements through agreements for the purchase of electrical capacity and energy from suppliers. These agreements, referred to as power purchase agreements are

- *NB Power Generation Corporation ("Vesting") PPA*

  Under the Vesting PPA, Disco has access to the capacity of all of the generation resources available to Genco. These include heritage power purchase agreements that Genco has with third parties.

  The pricing has two parts, a capacity payment $/megawatt ("$/MW") and an energy price $/megawatt-hour ("$/MWh"). The capacity payment covers the capital related costs associated with the generating plants including Coleson Cove. The capacity payment applies to the base load capacity nominated by Disco to meet its supply obligations. The Vesting PPA, as amended, also provides for Genco to invoice Disco for costs and expenses incurred by Genco related to the supply of additional electricity to Disco in relation to the PLGS refurbishment during the out of service period.

- *NB Power Coleson Cove Corporation ("Colesonco") PPA*

  Under the Colesonco PPA, Disco pays a payment based on plant capacity ($/MW), a fixed payment towards plant operations and maintenance costs, and a charge in $/MWh to cover variable costs.

All of the capacity and energy delivered under the Colesonco PPA is made available to Genco to be dispatched along with other generation resources to minimize the overall cost of production to meet in-province requirements.

The Vesting PPA capacity and energy charges incorporate all of the Colesonco capacity charges, payments towards operation and maintenance and the variable charges related to in-province energy supply.

- *NB Power Nuclear Corporation ("Nuclearco") PPA*

The Nuclearco PPA is for the supply of energy and capacity to Disco. Nuclearco is paid based on a single component price in $/MWh. As prescribed in the Nuclearco PPA, when Nuclearco does not operate, it does not get paid. However, during the period of the PLGS refurbishment project the billing provisions in the Nuclearco PPA are superseded by Section 143.1 of the *Electricity Act.* The legislation requires Nuclearco to record certain costs and expenses[1] incurred by Nuclearco in relation to the project during the "out of service period" [2] and invoice Disco monthly for the specified costs, net of certain revenues, during the out of service period.

The Genco, Colesonco and Nuclearco PPAs became effective on October 1, 2004.[3]

- *Renewable Energy PPAs and purchases from Industrial Customers with self-generation*

Other purchased power expense relates to Disco's energy purchases from renewable energy projects and from some of its industrial customers with self-generation (e.g.

[1] Certain costs and expenses are costs incurred by Nuclearco not associated with the refurbishment capital project and that would normally be expensed in the out of service period.

[2] "out of service period" means the period of time beginning when the Point Lepreau nuclear generating station is out of service due to the project until such time that the station returns to normal service (Section 143.1(1) of the *Electricity Act*).

[3] The Vesting PPA and Colesonco PPA have each been amended since October 1, 2004. The amendments can be categorized as clarification of language and intent, correction of errors and oversights, and changes to deal with new issues such as putting into effect the terms of the lawsuit settlement with PDVSA.

bio-mass, hydro, oil) that periodically supply energy back on the system when their load is less than their generation. Pursuant to the *Electricity Act*, Disco as the standard service supplier, is to ensure a portion of its electricity is obtained from renewable resources. Purchases from new renewable energy suppliers began in 2008/09. Purchased power cost from renewable energy sources is based on contracted $/MWh rates while energy supplied by industrial self-generating customers is based on 90% of avoided cost.

<u>Amendments to the PPAs</u>

In May 2010, the Vesting Agreement was amended to put into effect a clarification of how changes in CPI are applied to the Contribution to Fixed Costs starting in fiscal year 2010/11, a clarification of how third party purchase benefits are to be calculated, an insertion to the agreement to provide for the benefits of an efficiency improvement at the Belledune Generating Station to be passed through to Disco and its customers, an extension for establishing the Vesting Energy Price for fiscal year 2010/11, and a provision to adjust the Vesting Energy Price whenever the Point Lepreau Generating Station in-service date is known.

The Nuclearco PPA is not being amended at this time. Disco and Nuclearco agreed that an amendment is not required because

- Nuclearco is not selling energy to Disco during the PLGS refurbishment, there would have been no charges to Disco and therefore, unlike the Vesting PPA, there is no need to modify any pricing methodologies for the period
- the procedures for charging Nuclearco costs to Disco during the PLGS refurbishment in order to comply with the legislation are straightforward compared to those in the Vesting PPA
- the legislation directing Nuclearco to pass certain costs to Disco overrides the Nuclearco PPA

POWER PURCHASE AGREEMENTS (PPAs) - AMENDMENTS

Attached please find the following PPA Amendments

- Amendment No. 5 to Vesting Agreement
- Amendment No. 6 to Vesting Agreement

NEW BRUNSWICK POWER GENERATION CORPORATION

– and –

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION

– and –

NEW BRUNSWICK POWER HOLDING CORPORATION

AMENDMENT NO. 5 TO VESTING AGREEMENT

AMENDMENT NO. 5 TO VESTING AGREEMENT

THIS AMENDING AGREEMENT is made as of this 21st day of May, 2010,

B E T W E E N:

NEW BRUNSWICK POWER GENERATION CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

(“**Genco**”)

– and –

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

(“**Disco**”)

– and –

NEW BRUNSWICK POWER HOLDING CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

(“**NB Power Holdco**”)

RECITALS:

A. Genco, Disco and NB Power Holdco entered into a vesting agreement effective as of October 1, 2004, Amendment No. 1 to the vesting agreement on April 16, 2007, Amendment No. 2 to the vesting agreement on November 20, 2007, Amendment No. 3 to the vesting agreement on April 20, 2009 (“**Amendment No. 3**”), and Amendment No. 4 to the vesting agreement on April 20, 2009 (as so amended, the “**Vesting Agreement**”).

B. During the course of administering the Vesting Agreement, the parties have identified amendments they wish to make to clarify how changes in CPI (New Brunswick) are applied to the Contribution to Fixed Costs.

C. Schedule 6.2 of the Vesting Agreement was amended pursuant to Amendment No. 3 so that, among other things, estimates of Energy purchases to be made by Genco in order to supply Disco at a lower price than it otherwise would be able to using the Genco Heritage Assets would be considered when determining the Fuel Component of the Vesting Energy Price. Accordingly, the parties have agreed that the calculation of the benefit to Disco of third party purchases pursuant to Section 6.5 of the Vesting Agreement should be amended to reflect that Disco already receives the benefit of the estimated amounts of such Energy purchases that have been included in the calculation of the Fuel Component of the Vesting Energy Price.

D. Genco and Disco agreed that Genco would undertake a capital investment at Belledune Generating Station in order to improve the turbine output and efficiency of Belledune Generating Station, Unit 2, with no corresponding increase in fuel consumption. Genco was not required to undertake this capital investment pursuant to the terms of the Vesting Agreement. Accordingly, and since Disco will receive an economic benefit as a result of this capital investment, Disco has agreed to compensate Genco for this capital investment in accordance with the terms and conditions of this Amending Agreement.

NOW THEREFORE, in consideration of the mutual covenants and agreements set forth herein and other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged) the parties agree as follows:

1. <u>Definitions</u>

In this Amending Agreement:

1.1 "**Amending Agreement**" means this amending agreement, including the recitals and schedules hereto, as it may be amended, restated or replaced from time to time, and unless otherwise indicated, references to recitals, sections and schedules are references to recitals, sections and schedules in this amending agreement.

All other capitalized terms used in this Amending Agreement shall have the meanings ascribed to such terms in the Vesting Agreement.

2. Headings

The inclusion of headings in this Amending Agreement is for convenience of reference only and shall not affect the construction or interpretation of this Amending Agreement.

3. Gender and Number and Grammatical Changes

In this Amending Agreement, unless the context otherwise requires, words importing the singular include the plural and *vice versa* and words importing gender include all genders. Where a word or phrase is defined, its other grammatical forms have a corresponding meaning.

4. Invalidity of Provisions

Each of the provisions contained in this Amending Agreement is distinct and severable and a declaration of invalidity or unenforceability of any such provision or part thereof by a court of competent jurisdiction or an arbitrator shall not affect the validity or enforceability of any other provision of this Amending Agreement. To the extent permitted by Applicable Law, the parties waive any provision of Applicable Law which renders any provision of this Amending Agreement invalid or unenforceable in any respect. The parties shall engage in good faith negotiations to replace any provision which is declared invalid or unenforceable with a valid and enforceable provision, the legal and economic effect of which comes as close as possible to that of the invalid or unenforceable provision which it replaces.

5. Entire Agreement

The Vesting Agreement as previously amended and this Amending Agreement constitute the entire agreement between the parties pertaining to the subject matter of this Amending Agreement. There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in the Vesting Agreement or this Amending Agreement. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into this Amending

Agreement, or any amendment or supplement thereto, by a party to this Amending Agreement or its partners, shareholders, directors, officers, employees or agents, to the other parties to this Amending Agreement or their partners, shareholders, directors, officers, employees or agents, except to the extent that the same has been reduced to writing and included as a term of the Vesting Agreement or this Amending Agreement, and no party to this Amending Agreement has been induced to enter into this Amending Agreement or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact. Accordingly, there shall be no liability, either in tort or in contract, assessed in relation to any such warranty, representation, opinion, advice or assertion of fact, except to the extent contemplated above.

6. <u>Waiver</u>

No waiver of any provision of this Amending Agreement shall constitute a waiver of any other provision nor shall any waiver of any provision of this Amending Agreement constitute a continuing waiver or operate as a waiver of, or estoppel with respect to, any subsequent failure to comply, unless otherwise expressly provided.

7. <u>Governing Law</u>

This Amending Agreement and any Disputes shall be governed by and construed in accordance with the laws of the Province of New Brunswick and the laws of Canada applicable therein.

8. <u>Technical Terms</u>

Words or abbreviations that have well known technical or trade meanings are used in this Amending Agreement in accordance with their recognized meanings.

9. <u>Amendments</u>

The Vesting Agreement shall be amended as follows:

9.1 Section 6.2.6 of the Vesting Agreement shall be deleted in its entirety and replaced with the following, with such amendment to take effect as of March 31, 2010:

"6.2.6 The contribution to fixed costs will be $7.00/MWh for the Fiscal Year ending March 31, 2005 (the "**Contribution to Fixed Costs**"). For each Fiscal Year thereafter up to and including the Fiscal Year ending March 31, 2010, the Contribution to Fixed Costs will equal the product of (i) the Contribution to Fixed Costs for the immediately preceding Fiscal Year, and (ii) the CPI Adjustment for the calendar year ending on December 31 in the immediately preceding Fiscal Year. For the Fiscal Year ending March 31, 2011 and each Fiscal Year thereafter, the Contribution to Fixed Costs will equal the following:

6.2.6.1 the product of (i) the Contribution to Fixed Costs for the immediately preceding Fiscal Year, and (ii) one, if the CPI Factor (as defined in Schedule 1.1.30) for the calendar year ending on December 31 in the immediately preceding Fiscal Year is less than or equal to zero; or

6.2.6.2 the product of (i) the Contribution to Fixed Costs for the immediately preceding Fiscal Year, and (ii) one plus the product of (a) the CPI Factor (as defined in Schedule 1.1.30) for the calendar year ending on December 31 in the immediately preceding Fiscal Year, if the CPI Factor (as defined in Schedule 1.1.30) for such calendar year is greater than zero, and (b) one-third."

9.2 The following sentence shall be added to the end of Section 6.5 of the Vesting Agreement, with such amendment to take effect as of October 1, 2007:

"Notwithstanding the foregoing, Genco shall not be required to pay Disco for such excess to the extent that the amount of such excess has been included in the calculation of the Fuel Component of the Vesting Energy Price pursuant to section 6.2 and Schedule 6.2."

10. <u>Belledune Generating Station</u>

Disco and Genco have agreed that Genco should proceed to upgrade the turbine at the Belledune Generating Station (the "**Belledune Turbine Upgrade**") on the following terms and conditions:

10.1 Disco shall reimburse Genco for the costs and expenses incurred by Genco in connection with the Belledune Turbine Upgrade (collectively, the "**Belledune Turbine Upgrade Costs**") as follows:

10.1.1 Disco's obligation to reimburse Genco for the Belledune Turbine Upgrade Costs shall be capped at $11.3 million (the "**Belledune Turbine Upgrade Firm Estimate**") plus 50% of all actual Belledune Turbine Upgrade Costs incurred in excess of the Belledune Turbine Upgrade Firm Estimate. For greater certainty, Genco shall be solely responsible for 50% of the Belledune Turbine Upgrade Costs in excess of the Belledune Turbine Upgrade Firm Estimate.

10.1.2 If ultimately the Belledune Turbine Upgrade Costs are less than the Belledune Turbine Upgrade Firm Estimate, Disco shall be responsible for reimbursing Genco in aggregate for the amount of (i) the Belledune Turbine Upgrade Firm Estimate, less (ii) 50% of the difference between the Belledune Turbine Upgrade Firm Estimate and the Belledune Turbine Upgrade Costs.

10.1.3 Disco shall reimburse Genco by paying Genco the monthly payment calculated in accordance with Schedule A to this Amending Agreement. The first monthly payment shall be payable by Disco to Genco in the month immediately following the month in which Belledune Generating Station, Unit 2 ("**Belledune, Unit 2**") returns to service following completion of the Belledune Turbine Upgrade. Such monthly payment shall be payable by Disco to Genco each month until and including the month in which the Estimated Shutdown Date for Belledune, Unit 2 occurs, regardless of the date of the actual Shutdown of Belledune, Unit 2.

10.2 Notwithstanding Section 6.2 and Schedule 6.2 of the Vesting Agreement, for the purpose of determining the Fuel Component of the Vesting Energy Price, Disco and Genco have agreed that Genco will model Belledune, Unit 2 in PROMOD with an adjusted DNC (the "**DNC Adjustment**") as follows:

10.2.1 For the Fiscal Year ending March 31, 2011, the DNC Adjustment shall be 5 MW effective June 19, 2010, the expected return to service date for Belledune, Unit 2 following the Belledune Turbine Upgrade. Accordingly, effective June 19, 2010, 5 MW shall be added to the DNC for Belledune, Unit 2 for the Fiscal Year ending March 31, 2011.

10.2.2 For and including the Fiscal Year ending March 31, 2012 up to and including the Fiscal Year ending March 31, 2019, the DNC Adjustment shall be 5 MW. Accordingly, 5 MW shall be added to the DNC for Belledune, Unit 2 for and including the Fiscal Year ending March 31, 2012 up to and including the Fiscal Year ending March 31, 2019.

10.2.3 For and including the Fiscal Year ending March 31, 2020 up to the Estimated Shutdown Date for Belledune, Unit 2, the DNC Adjustment shall be the greater of (i) 3 MW, and (ii) the actual DNC for Belledune, Unit 2 as determined by the Operating Committee prior to the end of the Fiscal Year ending March 31, 2019, less 458.1 MW.

Notwithstanding the foregoing, if the date of the actual Shutdown of Belledune, Unit 2 occurs prior to the Estimated Shutdown Date for Belledune, Unit 2, the DNC Adjustment shall no longer apply as the DNC of Belledune, Unit 2 will no longer be included in PROMOD when determining the Fuel Component of the Vesting Energy Price.

10.3 Notwithstanding section 10.2, Disco and Genco have agreed that the DNC Adjustment provided for in section 10.2 shall not affect in any way the Nominated Capacity nor will the DNC Adjustment be amended as a result of a reduction in Nominated Capacity pursuant to Section 2.4.1 of the Vesting Agreement.

10.4 For the purpose of determining the Fuel Component of the Vesting Energy Price, Disco and Genco have agreed to adjust the guaranteed heat rate curve for Belledune, Unit 2 for the period following completion of the Belledune Turbine Upgrade to reflect the improved efficiency of Belledune, Unit 2. Disco and Genco agree that the Operating Committee shall agree on the adjusted guaranteed heat rate curve.

11. <u>Representations and Warranties of Genco</u>

Genco represents and warrants to Disco and NB Power Holdco as follows and acknowledges that each of Disco and NB Power Holdco is relying on such representations and warranties in entering into this Amending Agreement:

11.1 Genco is a corporation duly formed and existing under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

11.2 This Amending Agreement has been duly authorized, executed and delivered by Genco and is a valid and binding obligation of Genco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

11.3 The execution and delivery of this Amending Agreement by Genco and the performance by Genco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of Genco under:

> 11.3.1 any contract or obligation to which Genco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on Genco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;
>
> 11.3.2 the articles, by-laws or other organizational or constating documents of Genco; or
>
> 11.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to Genco.

11.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation or other similar proceedings pending against Genco or being contemplated by Genco or, to the Knowledge of Genco, threatened against Genco.

11.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

12. Representations and Warranties of Disco

Disco represents and warrants to Genco and NB Power Holdco as follows and acknowledges that each of Genco and NB Power Holdco is relying on such representations and warranties in entering into this Amending Agreement:

12.1 Disco is a corporation duly formed and existing under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

12.2 This Amending Agreement has been duly authorized, executed and delivered by Disco and is a valid and binding obligation of Disco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

12.3 The execution and delivery of this Amending Agreement by Disco and the performance by Disco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of Disco under:

12.3.1 any contract or obligation to which Disco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on Disco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;

12.3.2 the articles, by-laws or other organizational or constating documents of Disco; or

12.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to Disco.

12.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation, or other similar proceedings pending against Disco or being contemplated by Disco or, to the Knowledge of Disco, threatened against Disco.

12.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

13. Representations and Warranties of NB Power Holdco

NB Power Holdco represents and warrants to Genco and Disco as follows and acknowledges that each of Genco and Disco is relying on such representations and warranties in entering into this Amending Agreement:

13.1 NB Power Holdco is a corporation duly continued under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

13.2 This Amending Agreement has been duly authorized, executed and delivered by NB Power Holdco and is a valid and binding obligation of NB Power Holdco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

13.3 The execution and delivery of this Amending Agreement by NB Power Holdco and the performance by NB Power Holdco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of NB Power Holdco under:

13.3.1 any contract or obligation to which NB Power Holdco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on NB Power Holdco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;

13.3.2 the articles, by-laws or other organizational or constating documents of NB Power Holdco; or

13.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to NB Power Holdco.

13.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation, or other similar proceedings pending against NB Power Holdco or being contemplated by NB Power Holdco or, to the Knowledge of NB Power Holdco, threatened against NB Power Holdco.

13.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

14. Further Assurances

Each of the parties shall promptly do, take, execute or deliver or cause to be done, taken, executed or delivered all such further acts, steps, deeds, documents, assurances and things as the other parties may reasonably require from time to time for the purpose of giving effect to this Amending Agreement and shall use Commercially Reasonable Efforts and take all such steps as may be reasonably within its power to implement to their full extent the provisions of this Amending Agreement.

15. Counterparts

This Amending Agreement may be signed in counterparts and each of such counterparts shall constitute an original document and such counterparts, taken together, shall constitute one and the same instrument.

IN WITNESS WHEREOF, and intending to be legally bound, the parties have executed this Amending Agreement by the undersigned duly authorized representatives as of the date first stated above.

NEW BRUNSWICK POWER GENERATION CORPORATION

by: ______________________
Name: Blair Kennedy
Title: VP Generation

by: ______________________
Name: Wanda J Harrison
Title: Corporate Secretary

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION

SERVICES JURIDIQUES

LEGAL

by: ______________________
Name: Sherry Thomson
Title: VP Customer Service, Distribution and Transmission

by: ______________________
Name: Wanda J Harrison
Title: Corporate Secretary

NEW BRUNSWICK POWER HOLDING CORPORATION

by: ______________________
Name: Darren Murphy
Title: VP Finance

by: ______________________
Name: Wanda J Harrison
Title: Corporate Secretary

SCHEDULE A
PAYMENT OF BELLEDUNE TURBINE UPGRADE COSTS

FORMULA

The following formula shall be used to calculate the monthly payment from Disco to Genco in respect of the Belledune Turbine Upgrade Costs:

M	=	**(PMT+OC) / 12)**, where:

"**M**" equals:	The monthly payment payable to Genco by Disco.
"**I**" equals:	The amount of the Belledune Turbine Upgrade Costs for which Disco is required to reimburse Genco under the terms of this Amending Agreement, expressed in dollars of the Fiscal Year in which the monthly payment is first payable.
"**L**" equals:	The levelizing factor, which for purposes of this Amending Agreement shall equal: $w/(1-(1/(1+w)^n))$.
"**t**" equals:	The tax rate applicable to Genco as of the Fiscal Year in which the monthly payment is first payable, expressed in decimals.
"**n**" equals:	The period in years from the date the monthly payment is first payable to the Estimated Shutdown Date in respect of Belledune Generating Station, Unit 2, which Estimated Shutdown Date, for greater certainty, shall not be extended for purposes of this calculation as a result of such Belledune Turbine Upgrade Costs being incurred.
"**w**" equals:	The pre-tax weighted average cost of capital, which for purposes of this Amending Agreement shall equal d x DR + (r/(1-t)) x ER.
"**d**" equals:	Genco's reasonable cost of borrowing as of the Fiscal Year in which the monthly payment is first payable, expressed in decimals.
"**DR**" equals:	Genco's debt ratio, which for purposes of this Amending Agreement shall equal 0.55.
"**r**" equals:	Genco's rate of return on equity, which for purposes of this Amending Agreement shall equal 0.11.
"**ER**" equals:	Genco's equity ratio, which for purposes of this Amending Agreement shall equal 0.45.
"**PMT**" equals:	I x L
"**OC**" equals:	The projected change in annual operations and maintenance costs resulting from or associated with the expenditure of the Belledune Turbine Upgrade Costs, if any.

EXAMPLE

The following example sets forth how the formula shall be used to calculate the monthly payment from Disco to Genco in respect of the Belledune Turbine Upgrade Costs. For purposes of these examples, it is assumed that:

(i) the Estimated Shutdown Date is March, 2020;

(ii) I = $10,000,000 in the Fiscal Year ended March, 2010;

(iii) Genco's reasonable cost of borrowing as of the Fiscal Year in which the monthly payment is first payable is 5% and therefore for purposes of this example only "**d**" equals 0.05;

(iv) the tax rate applicable to Genco as of the Fiscal Year in which the monthly payment is first payable is 28.80% and therefore for purposes of this example only "**t**" equals .2880; and

(v) OC equals zero.

"w"	=	d x DR + (r/(1-t)) x ER
	=	0.05 x 0.55 + (0.11/(1 - 0.2880)) x 0.45
	=	0.0275 + 0.0695 = 0.097 or 9.7%
"L"	=	$w/(1-(1/(1+w)^n))$
	=	$0.097/(1 - (1/(1 + 0.097)^{10}))$
	=	0.097/(1 - (1/(2.5239))
	=	0.097/(1 - 0.3962) = 0.1607
PMT	=	($10,000,000 x 0.1607) = $1.607 million
M	=	($1.607 million + 0)/12
	=	$133,916.67 per month

NEW BRUNSWICK POWER GENERATION CORPORATION

– and –

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION

– and –

NEW BRUNSWICK POWER HOLDING CORPORATION

AMENDMENT NO. 6 TO VESTING AGREEMENT

AMENDMENT NO. 6 TO VESTING AGREEMENT

THIS AMENDING AGREEMENT is made as of this 21st day of May, 2010,

B E T W E E N:

NEW BRUNSWICK POWER GENERATION CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

("**Genco**")

– and –

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

("**Disco**")

– and –

NEW BRUNSWICK POWER HOLDING CORPORATION, a duly incorporated company under and by virtue of the laws of the Province of New Brunswick, with head office therein at the City of Fredericton, in the County of York

("**NB Power Holdco**")

RECITALS:

A. Genco, Disco and NB Power Holdco entered into a vesting agreement effective as of October 1, 2004, Amendment No. 1 to the vesting agreement on April 16, 2007, Amendment No. 2 to the vesting agreement on November 20, 2007, Amendment No. 3 to the vesting agreement on April 20, 2009, Amendment No. 4 to the vesting agreement on April 20, 2009, and Amendment No. 5 to the vesting agreement on May 21, 2010 (as so amended, the "**Vesting Agreement**").

B. During the Fiscal Year ending March 31, 2010, the Province of New Brunswick and the Province of Québec discussed the sale of all or a portion of the direct or indirect assets of NB Power Holdco. Ultimately, this proposed transaction did not proceed. However, as a result thereof, the parties decided to allow three additional months for the determination of the Vesting Energy Price for the Fiscal Year ending March 31, 2011.

C. The parties expect that the Point Lepreau Refurbishment In-Service Date will be extended. As a result, the parties wish to amend Schedule 6.2 of the Vesting Agreement to contemplate such extended date.

NOW THEREFORE, in consideration of the mutual covenants and agreements set forth herein and other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged) the parties agree as follows:

1. Definitions

In this Amending Agreement:

1.1 "**Amending Agreement**" means this amending agreement, including the recitals hereto, as it may be amended, restated or replaced from time to time, and unless otherwise indicated, references to recitals and sections are references to recitals and sections in this amending agreement.

All other capitalized terms used in this Amending Agreement shall have the meanings ascribed to such terms in the Vesting Agreement.

2. Headings

The inclusion of headings in this Amending Agreement is for convenience of reference only and shall not affect the construction or interpretation of this Amending Agreement.

3. Gender and Number and Grammatical Changes

In this Amending Agreement, unless the context otherwise requires, words importing the singular include the plural and *vice versa* and words importing gender include all genders. Where a word or phrase is defined, its other grammatical forms have a corresponding meaning.

4. Invalidity of Provisions

Each of the provisions contained in this Amending Agreement is distinct and severable and a declaration of invalidity or unenforceability of any such provision or part thereof by a court of competent jurisdiction or an arbitrator shall not affect the validity or enforceability of any other provision of this Amending Agreement. To the extent permitted by Applicable Law, the parties waive any provision of Applicable Law which renders any provision of this Amending Agreement invalid or unenforceable in any respect. The parties shall engage in good faith negotiations to replace any provision which is declared invalid or unenforceable with a valid and enforceable provision, the legal and economic effect of which comes as close as possible to that of the invalid or unenforceable provision which it replaces.

5. Entire Agreement

The Vesting Agreement as previously amended and this Amending Agreement constitute the entire agreement between the parties pertaining to the subject matter of this Amending Agreement. There are no warranties, conditions, or representations (including any that may be implied by statute) and there are no agreements in connection with such subject matter except as specifically set forth or referred to in the Vesting Agreement or this Amending Agreement. No reliance is placed on any warranty, representation, opinion, advice or assertion of fact made either prior to, contemporaneous with, or after entering into this Amending Agreement, or any amendment or supplement thereto, by a party to this Amending Agreement or its partners, shareholders, directors, officers, employees or agents, to the other parties to this Amending Agreement or their partners, shareholders, directors, officers, employees or agents, except to the extent that the same has been reduced to writing and included as a term of the Vesting Agreement or this Amending Agreement, and no party to this Amending Agreement has been induced to enter into this Amending Agreement or any amendment or supplement by reason of any such warranty, representation, opinion, advice or assertion of fact. Accordingly, there shall be no liability, either in tort or in contract, assessed in relation to any such warranty, representation, opinion, advice or assertion of fact, except to the extent contemplated above.

6. Waiver

No waiver of any provision of this Amending Agreement shall constitute a waiver of any other provision nor shall any waiver of any provision of this Amending Agreement constitute a continuing waiver or operate as a waiver of, or estoppel with respect to, any subsequent failure to comply, unless otherwise expressly provided.

7. Governing Law

This Amending Agreement and any Disputes shall be governed by and construed in accordance with the laws of the Province of New Brunswick and the laws of Canada applicable therein.

8. Technical Terms

Words or abbreviations that have well known technical or trade meanings are used in this Amending Agreement in accordance with their recognized meanings.

9. Amendments

The Vesting Agreement shall be amended as follows:

9.1 Notwithstanding Section 6.2.4 of the Vesting Agreement, the parties agree that the Vesting Energy Price for the Fiscal Year ending March 31, 2011 shall be established by the Operating Committee in accordance with Section 6.2 and Schedule 6.2 by June 30, 2010.

9.2 The words "anytime prior to March 31, 2010" in the second paragraph in Item 5 of Schedule 6.2 of the Vesting Agreement shall be deleted, with such amendment to take effect as of March 31, 2010.

10. Representations and Warranties of Genco

Genco represents and warrants to Disco and NB Power Holdco as follows and acknowledges that each of Disco and NB Power Holdco is relying on such representations and warranties in entering into this Amending Agreement:

10.1 Genco is a corporation duly formed and existing under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

10.2 This Amending Agreement has been duly authorized, executed and delivered by Genco and is a valid and binding obligation of Genco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

10.3 The execution and delivery of this Amending Agreement by Genco and the performance by Genco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of Genco under:

10.3.1 any contract or obligation to which Genco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on Genco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;

10.3.2 the articles, by-laws or other organizational or constating documents of Genco; or

10.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to Genco.

10.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation or other similar proceedings pending against Genco or being contemplated by Genco or, to the Knowledge of Genco, threatened against Genco.

10.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

11. <u>Representations and Warranties of Disco</u>

Disco represents and warrants to Genco and NB Power Holdco as follows and acknowledges that each of Genco and NB Power Holdco is relying on such representations and warranties in entering into this Amending Agreement:

11.1 Disco is a corporation duly formed and existing under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

11.2 This Amending Agreement has been duly authorized, executed and delivered by Disco and is a valid and binding obligation of Disco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

11.3 The execution and delivery of this Amending Agreement by Disco and the performance by Disco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of Disco under:

> 11.3.1 any contract or obligation to which Disco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on Disco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;
>
> 11.3.2 the articles, by-laws or other organizational or constating documents of Disco; or
>
> 11.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to Disco.

11.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation, or other similar proceedings pending against Disco or being contemplated by Disco or, to the Knowledge of Disco, threatened against Disco.

11.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

12. Representations and Warranties of NB Power Holdco

NB Power Holdco represents and warrants to Genco and Disco as follows and acknowledges that each of Genco and Disco is relying on such representations and warranties in entering into this Amending Agreement:

12.1 NB Power Holdco is a corporation duly continued under the laws of New Brunswick and has the corporate power and capacity to enter into this Amending Agreement and to perform its obligations hereunder.

12.2 This Amending Agreement has been duly authorized, executed and delivered by NB Power Holdco and is a valid and binding obligation of NB Power Holdco enforceable in accordance with its terms, subject to the usual exceptions as to bankruptcy and the availability of equitable remedies.

12.3 The execution and delivery of this Amending Agreement by NB Power Holdco and the performance by NB Power Holdco of its obligations hereunder will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any obligation of NB Power Holdco under:

12.3.1 any contract or obligation to which NB Power Holdco is a party or by which it or its assets may be bound, except for such breaches, violations, defaults, conflicts, terminations, cancellations or accelerations as to which requisite waivers or consents have been obtained or which would not have a material adverse effect on NB Power Holdco's ability to fulfil or perform its obligations and covenants under this Amending Agreement;

12.3.2 the articles, by-laws or other organizational or constating documents of NB Power Holdco; or

12.3.3 any judgment, decree, law, statute, regulation, rule, licence, permit, certificate, registration, approval, consent, authorization, order, ruling or award of any Governmental Authority having jurisdiction over or applicable to NB Power Holdco.

12.4 There are no bankruptcy, insolvency, receivership, interim-receivership, seizure, realization, liquidation, or other similar proceedings pending against NB Power Holdco or being contemplated by NB Power Holdco or, to the Knowledge of NB Power Holdco, threatened against NB Power Holdco.

12.5 All of the foregoing representations and warranties will continue to be true and correct until the Termination Date or such earlier date on which the Vesting Agreement may be terminated.

13. Further Assurances

Each of the parties shall promptly do, take, execute or deliver or cause to be done, taken, executed or delivered all such further acts, steps, deeds, documents, assurances and things as the other parties may reasonably require from time to time for the purpose of giving effect to this Amending Agreement and shall use Commercially Reasonable Efforts and take all such steps as may be reasonably within its power to implement to their full extent the provisions of this Amending Agreement.

14. Counterparts

This Amending Agreement may be signed in counterparts and each of such counterparts shall constitute an original document and such counterparts, taken together, shall constitute one and the same instrument.

IN WITNESS WHEREOF, and intending to be legally bound, the parties have executed this Amending Agreement by the undersigned duly authorized representatives as of the date first stated above.

NEW BRUNSWICK POWER GENERATION CORPORATION

by: Blair Kennedy
Name: Blair Kennedy
Title: VP Generation

by: Wanda J Harrison
Name: Wanda J Harrison
Title: Corporate Secretary

NEW BRUNSWICK POWER DISTRIBUTION AND CUSTOMER SERVICE CORPORATION

SERVICES JURIDIQUES
LEGAL

by: Sherry Thomson
Name: Sherry Thomson
Title: VP Customer Service, Distribution and Transmission

by: Wanda J Harrison
Name: Wanda J Harrison
Title: Corporate Secretary

NEW BRUNSWICK POWER HOLDING CORPORATION

by: Darren Murphy
Name: Darren Murphy
Title: VP Finance

by: Wanda J Harrison
Name: Wanda J Harrison
Title: Corporate Secretary