DECISION

IN THE MATTER of an Application **by the New Brunswick Power Distribution & Customer Service Corporation (DISCO) for changes to its Charges, Rates and Tolls**

June 19, 2006

NEW BRUNSWICK

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER of an Application dated March 21, 2005 by the New Brunswick Power Distribution and Customer Service Corporation for the Approval of a Change in its Charges, Rates and Tolls.

1. PARTICIPANTS

Board:	David C. Nicholson, Chairman David S. Nelson, Vice-Chairman C. Randall Bell, Commissioner Patricia LeBlanc-Bird, Commissioner Jacques A. Dumont, Commissioner Kenneth F. Sollows, Commissioner Diana Ferguson Sonier, Commissioner H. Brian Tingley, Commissioner
Board Staff:	Lorraine R. Légère, Secretary to the Board M. Douglas Goss, Senior Advisor John Lawton, Advisor
Board Consultants:	Peter A. MacNutt, Q.C., Board Counsel James Easson, CA, Consultant Andrew Logan, CA, Consultant John Murphy, Consultant Arthur W. Adelberg, Witness Steven S. Garwood, Witness
Applicant:	
New Brunswick Power Distribution & Customer Service Corporation	Sharon MacFarlane, CA Rock Marois Lori Clark Blair Kennedy

	Neil Larlee
	Tony O'Hara
	David Hashey, Q.C., Counsel
	Terry Morrison, Counsel
	Peter Ruby, Counsel
	Clare Roughneen, Counsel
	Kathleen McShane, Consultant
	Daniel Peaco, Consultant
	Dr. Malcolm Bridger, Consultant
	Malcolm R. Ketchum, Consultant

Formal Intervenors:

Bayside Power L.P.	Christopher Stewart, Counsel
Canadian Manufacturers & Exporters	David Plante Gary Lawson, Counsel
Conservation Council of New Brunswick	David Coon
Canadian Broadcasting Corporation & Telegraph Journal	David Coles, Q.C., Counsel
Eastern Wind Power Inc.	Paul Woodhouse Peter MacPhail, Counsel
Enbridge Gas New Brunswick Inc.	Andrew Harrington Shelley Black Ruth York David MacDougall, Counsel Dr. Alan Rosenberg, Consultant

Energy Probe Research Foundation

Rodney J. Gillis, Q.C.

Irving Paper Limited	William Dever Andrew Booker
Irving Pulp & Paper Limited	Kevin McCarthy Mark Mosher
J.D. Irving Limited	Wayne Wolfe Thomas Storing
Jolly Farmer Products	Jonathan English
New Brunswick Municipal Electric Utility Association	Richard Burpee, Saint John Energy Eric Marr, Saint John Energy Dana Young, Saint John Energy Charles Martin, Energie Edmundston Dan Dionne, Perth-Andover Electric Light Raymond Gorman, Q.C., Counsel Paula Zarnett, Consultant
Rogers Cable Communications Inc.	Christianne Vaillancourt Leslie Milton, Counsel John Armstrong Clinton Lawrence Donald Ford, Consultant Dr. Roger Ware, Consultant
Self-Represented Individuals	Jan Rowinski

	Eric Allaby
	Chris Baker
	Erik Denis
	Shawn Graham
	Stuart Jamieson
	Roly MacIntyre
Vibrant Communities Saint John	Tom Gribbons
	Kurt Peacock
Public Intervenor:	Peter Hyslop
	Carolanne Power
	Robert O'Rourke, Consultant
	Robert D. Knecht, Consultant
	Donald Barnett, Consultant
	Dr. Kurt Strunk, Consultant
	Dr. Jeff Makholm, Consutlant

Informal Intervenors:

Agriculture Producer's Association of New Brunswick

Atlantic Centre for Energy

Canadian Council of Grocery Distributors

City of Miramichi

Falconbridge Limited

Flakeboard Company Limited

New Brunswick Power Generation Corp.

New Brunswick System Operator

Potash Company of Saskatchewan

Terry Thomas Consulting

UPM-Kymmene Miramichi Inc.

2. INTRODUCTION

General:

The New Brunswick Power Distribution and Customer Service Corporation (DISCO) filed an application with the New Brunswick Board of Commissioners of Public Utilities (the Board), dated March 21, 2005, for approval of a change in its charges, rates and tolls. Section 101 of the Electricity Act (the Act) requires DISCO to apply to the Board for approval of changes in its charges, rates and tolls where such changes exceed the amount authorized under Section 99 of the Act.

DISCO requested that the Board hear the application in two phases as follows:

Phase One: That the Board make an order that would allow it to recover, at a later date and in a manner determined by the Board, the amount by which its fuel costs, encompassed in its purchased power costs as of April 1, 2005, exceeded the amount recovered through its charges, rates and tolls as currently filed. Additionally, it requested approval of a variable fuel surcharge going forward.

Phase Two: That the Board approve its revenue requirement, cost allocation and rate alignment proposals and proposed rates, charges and tolls as filed with the application.

The Pre-hearing Conference began on May 17, 2005. The Board granted intervenor status to various parties. DISCO requested the Board to rule on its phasing proposal and the hearing process before establishing a schedule for the hearing.

Various parties presented oral arguments concerning DISCO's request for approval of a fuel variance account (deferral account) and a variable fuel surcharge. The intervenors were requested to submit written briefs by May 24, 2005 and DISCO was to submit its rebuttal comments by May 26, 2005. The Board also heard arguments from DISCO, the New Brunswick Municipal Electrical Utility Association (the Municipals) and Rogers Cable Communications Inc. (Rogers) concerning the Board's authority to set the rate for third party pole attachments.

The Pre-hearing Conference reconvened on May 30, 2005 at which time the Board ruled against DISCO's request for approval of a fuel variance account. Such an account would have allowed DISCO to recover the difference between its actual fuel costs and the amount it had forecast for fuel costs in its current rates, prior to the effective date of the Board's decision on this application. The Board stated that to approve the use of a variance account would effectively result in approval for an interim rate increase and that it had no authority under the Act to do so. DISCO requested an adjournment which was granted until June 8, 2005. A copy of the ruling is included in Appendix A.

On June 6, 2005, DISCO wrote and informed the Board that, pursuant to Section 99 of the Act, it would be increasing rates by 3 percent effective July 7, 2005. That increase replaced DISCO's request for approval of a change in its rates for the 2005/06 fiscal period. DISCO also informed the Board that it intended to amend its application with a request to change its charges, rates and tolls for its fiscal period 2006/07.

DISCO had filed its Phase Two evidence on Cost Allocation and Rate Design (CARD) with the Board on April 17, 2005. CARD is the process of allocating a utility's costs between customer classes and using them in designing rates. The schedule allowed for three rounds of intervenor interrogatories with responses by DISCO. Intervenor evidence was filed on September 6, 2005 and the schedule allowed for one round of interrogatories and responses on that evidence.

The pre-hearing conference was held over 10 days from May 17th to September 19th during which the Board heard arguments regarding the fuel variance account, confidentiality and media access to the hearing room. The Board issued a ruling on July 27, 2005 on media access and on the confidentiality of information filed under section

133 of the Act. A copy is attached as Appendix B. The CARD phase of the hearing began on September 26, 2005.

The Board considered that it was appropriate to review DISCO's load forecast for the 2006/07 test year while the CARD phase of the hearing was underway. That review was held on November 21, 2005. The Board issued its ruling on CARD and the 2006/07 Load Forecast on December 21, 2005, a copy is attached as Appendix D.

DISCO filed its revenue requirement evidence on October 17, 2005 and its revised Class Cost Allocation Study (CCAS) and 2006/07 rate proposal were filed on January 24, 2006. A CCAS determines the allocation of a utility's costs amongst its customer classes. Interrogatories and responses were exchanged between the parties and additional motions days were held to hear arguments regarding confidentiality for interrogatory responses, the appropriateness of interrogatory responses and issues concerning the Public Intervenor's proposed evidence. The Public Intervenor (PI) filed evidence on January 30 and February 17, 2006.

The revenue requirement phase of the hearing began on February 6, 2006. The Board held a "Public Day" on March 3, 2006 at which members of the public and informal intervenors made oral presentations. The presenters spoke on a number of topics including the following:

1. The financial burden of electricity costs on families and business
2. The lack of a competitive electricity market
3. In support of and the need for greater regulation by the Board
4. In support of a fuel surcharge
5. That DISCO and GENCO should continue their progress to reduce operating costs
6. That a rate of return should not be guaranteed
7. NB Power's failure to reduce the overpayment by some customer classes since 1988/89.

The presentations gave valuable insight to the effects that the cost of electricity has on the people and businesses of New Brunswick. The Board wishes to thank all the parties who made presentations. Following is a list of the presenters.

Daniel Laberge	Bowater Maritimes
Stéphane Robichaud	Canadian Federation of Independent Business
Mark Arsenault	NB Forest Products Association
Ted Shannon	Falconbridge
Alex Arsenault	Individual Presenter
Allan Walker	McCains Canada
Allison Brewer	New Democratic Party of New Brunswick
Ashley London	Credit Counseling of Canada
Christina Payne	Individual Presenter
Charles Collins	Individual Presenter
Gary Dewitt	UPM-Kymmene Miramichi
John McKay	City of Miramichi
Lois Dunfield	Common Front for Social Justice
Brenda Dunn	Communications, Energy and Paperworkers
Nasir El-Jabi	Université de Moncton
Ellen Creighton	New Brunswick Student Alliance
Stan Smith	Town of St. George
Barry Gallant	Flakeboard
Wendy Osborne	New Brunswick Chamber of Commerce
Scott Donnelly	New Brunswick Natural Gas Association
Werner Bock	Individual Presenter

Restructuring:

In accordance with provisions of the Act, the New Brunswick Power Corporation (NB Power) applied for continuance under the Business Corporations Act under the name New Brunswick Power Holding Corporation, (HOLDCO).

Subsequently, HOLDCO created the following operating subsidiary corporations:

New Brunswick Power Nuclear Corporation (NUCLEARCO)
New Brunswick Power Generation Corporation (GENCO)
New Brunswick Power Transmission Corporation (TRANSCO)
New Brunswick Power Distribution and Customer Service Corporation (DISCO)

In addition, GENCO has two wholly owned subsidiaries, New Brunswick Power Coleson Cove Corporation (COLESONCO) and NB Coal Limited (NB Coal)
Ms. MacFarlane described the key objectives of the restructuring as being:

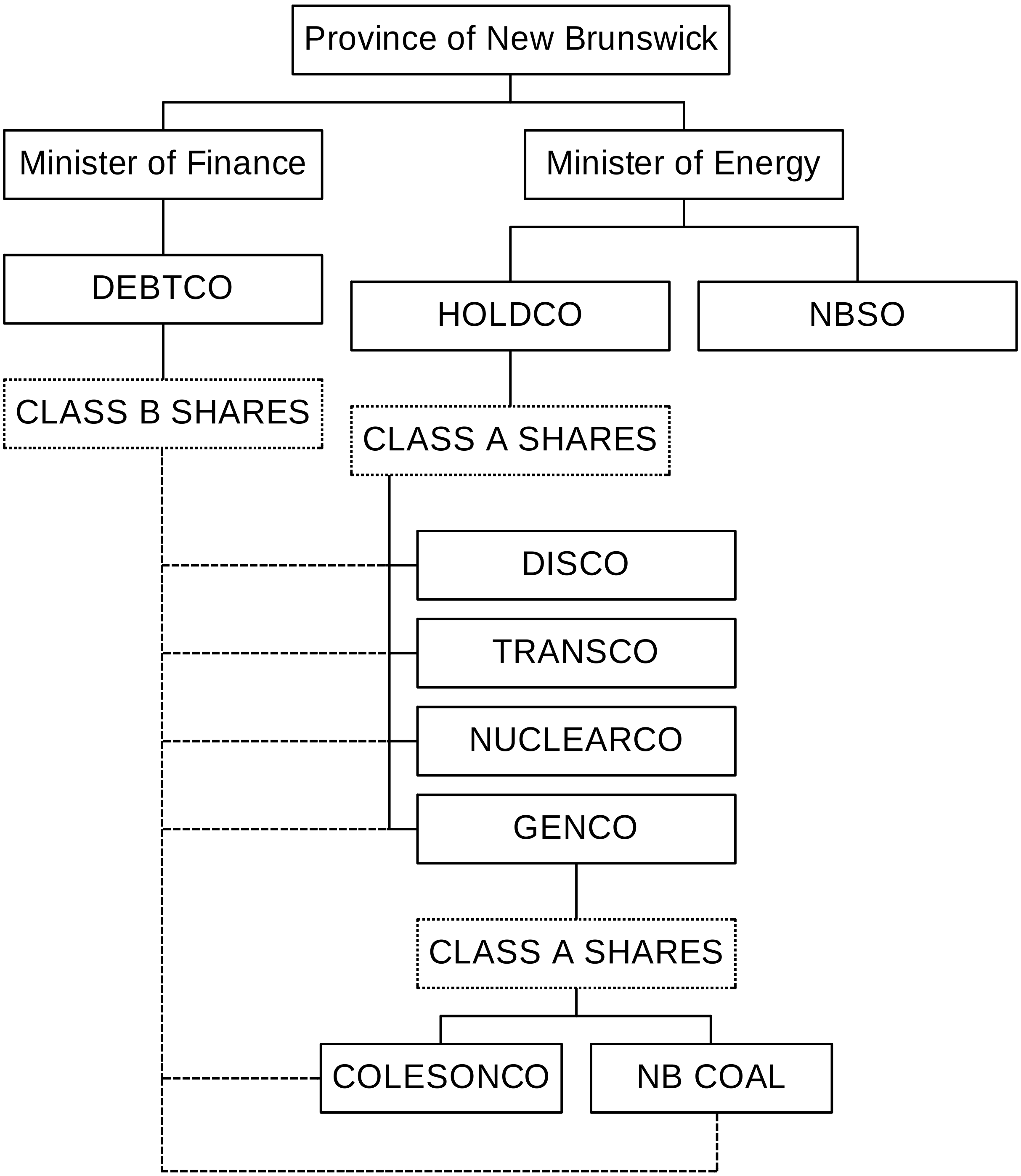
1. To structure the utility to operate on a level playing field so as to facilitate a managed transition to a competitive market for energy in New Brunswick, and
2. To assign the risk associated with the power supply business between the shareholder and ratepayer in a manner reflecting commercial industry practice.

The Act also created two other subsidiaries in furtherance of its objectives;

New Brunswick Electric Finance Corporation (EFC or DEBTCO)
New Brunswick System Operator (NBSO)

The Province of New Brunswick is the sole shareholder of HOLDCO, which in turn owns the Class A voting shares of NUCLEARCO, GENCO, TRANSCO and DISCO, while DEBTCO owns the Class B non-voting shares of these corporations. The effect of this structure is that HOLDCO controls the four operating corporations and is in turn controlled by the Province through the Minister of Energy.

OWNERSHIP STRUCTURE



Throughout the hearing parties stated that although NB Power had been restructured, it still operated as a fully integrated utility and that a competitive electricity market did not exist in New Brunswick. DISCO commented:

> *"It is our submission that regardless of the fact that Mr. Knecht and Dr. Rosenberg perceive NB Power as a vertically integrated utility, at law it is not. Pursuant to sections 3 and 4 of the Electricity Act, NB Power was transformed from a vertically integrated utility into a holding company and four distinct corporate legal entities.*
>
> *They were created by the Electricity Act but as all other business corporations in New Brunswick, they are governed by the Business Corporations Act and have the capacity, powers and privileges of an actual person. Also, the PUB recognized that it does not regulate Genco or Nuclear Co."* (Transcript, p. 2328)

EGNB's witness, Dr. Rosenberg, made the following comment.

> *"…NB Power is an unbundled utility in name only. In other words, it looks like a vertically integrated utility. You know, looks like a duck, walks like a duck, quacks, I think that it's for all intents and purposes a vertically integrated utility despite the restructuring. At least at this time*."(Transcript, p. 1498)

Mr. Knecht, the Public Intervenor's witness, stated in his evidence.

> *"At this stage, I interpret NB Power has having been partially restructured. While the company has been organizationally unbundled, generation planning continues to be done on an integrated basis, competition is non-existent and the PPAs do not represent arms-length transactions."* (Exhibit PI-2, p. 12)

Mr. Booker, representing JD Irving, stated in his summation.

"One common theme throughout the hearing has been the manner in which the structure of the NB Power group of companies has been developed in response to the Electricity Act. We share the frustrations of many in the room at the inability to look at what we see as the bulk of the cost elements which are driving the proposed increase. From the beginning, JDI supported a competitive electricity market. We participated actively in the Market Design Committee and continue to participate in the Market Advisory Committee.

NB Power was structured to compete in an open marketplace, and clearly this market has not developed. Originally, it was anticipated that the New Brunswick electricity market would develop to the point that transmission customers could contract with one of a number of distributors. These distributors in turn would source their electricity from amongst several generating companies."

[. . .] *"Today, however, we effectively have a situation where a single generation company effectively controls almost all generation assets and a single distribution company purchases almost all of this energy, and sells to all eligible customers. Thus, while in theory a competitive market can exist in New Brunswick, the reality is much different. As a result we have an extraordinary situation whereby power purchase agreements are utilized to flow costs through what is, in effect, still essentially a vertically integrated utility. As a result of these concerns, we recommend that the Board suggest modifications to the Electricity Act to allow the market to be restructured to allow full disclosure until the market truly opens."*(Transcript, p. 6057-9)

Mr. Walker, representing McCains Canada, commented:

"we would urge that in the absence of true competition in the generating sector, that they be subject to the oversight that the PUB is currently not permitted to give them." (Transcript, p. 5227)

3. ISSUES SUMMARY

The Board considers that all users should bear a portion of the joint and common costs incurred to provide their service. However, the Board rejects the specific rate proposals of both DISCO and Rogers due to the nature of the underlying data. After consideration of the evidence placed before it and the decisions in other jurisdictions, the Board believes that an annual rate of $18.00 per pole for 2006/07 is appropriate. (p.29)

The Board directs DISCO to undertake a study into its poles, equipment and related costs that will be used to review attachment rates at a future hearing. DISCO is instructed to consult with Board staff, Rogers and the Municipals to determine the scope of the study. (p.29)

For the purposes of this hearing, Section 156 of the Act requires the Board to accept any expenditures arising from the Power Purchase Agreements as necessary for the provision of the service. The Board must therefore accept $1.028 billion as the expense for purchased power for 2006/07. (p.29-30)

The Board appreciates and shares Mr. Hyslop’s concern with controlling the Operation, Maintenance and Administration (OM&A) expenses. However, no specific evidence was presented to support the reduction proposed by Mr. Hyslop. The Board expects DISCO to pursue ways to reduce OM&A expenses. The Board will, for 2006/07, accept an amount of $98.9 million for OM&A expenses. (p.31)

The Board believes that energy efficiency and Demand Side Management (DSM) are topics that require further research by DISCO. The Board directs DISCO to undertake a review of Canadian utilities’ energy efficiency and DSM programs including evaluation methods used to identify the cost benefits. This review is to be filed with the Board within six months of the date of this decision. (p.32)

The Board believes that the topic of establishing an arrears fund would be best canvassed during the hearing into DISCO's customer service policies. (p.32)

DISCO is directed to undertake an investigation into current utility practices relating to customer credit and collections. (p.34)

The Board will require DISCO to implement a Universal System of Accounts. (p.35)

The Board orders DISCO to compile a comprehensive Capital Justification Criteria Manual and file it with the Board within six months of the date of this decision. (p.36)

The Board appreciates DISCO's intention to complete a study on its amortization practices and directs that it be filed with the Board within six months of the date of this decision. (p.36)

In the opinion of the Board, the response of DISCO to the legislation is unsatisfactory and the Board orders DISCO to formulate a strategy that would utilize all aspects of the applicable income tax acts in order to minimize Payment In Lieu of Taxes. (p.40-41)

The Board does not consider it appropriate to use the deemed equity method to establish the forecast net income of DISCO for 2006/07. The Board considers that the use of the interest coverage method is more suitable. (p.41)

DISCO's proposed net income of $14.4 million requires an income before interest expense of $62.6 million. This level of income together with the forecast interest expense of $39.4 million produces an interest coverage of 1.59x. The Board considers this coverage to be excessive and will reduce the revenue requirement as discussed below. (p.42)

We believe that setting rates at a level that will permit the utility, over time, to earn an interest coverage ratio of 1.25x will allow it to ultimately raise capital without a Government guarantee. (p.42)

Fairness suggests that the target for each class of customers should be a revenue to cost ratio of 1:1. In other words, the revenues from each class should equal the costs of providing service to that class. (p.43)

The Board has prepared Table A to show the changes in revenue necessary to provide an interest coverage of 1.25 and to have a revenue to cost ratio of 1:1 for each class. (p.43)

Table A shows that the required increase in revenue would be $87.7 million for the Residential class and $56.7 million for the Large Industrial class. The Board considers that increases of this size in one year are too drastic. (p.44)

The Board feels that it must break with normal regulatory practice and set rates that will neither return the recommended interest coverage ratio of 1.25x nor target a revenue to cost ratio of 1:1 for each customer class. (p.44-45)

The Board considers that an interest coverage ratio target of 1.10 is appropriate for 2006/07. (p.45)

The total revenue requirement for 2006/07 approved by the Board is $1.2887 billion. This represents an increase in the total revenue requirement of 8.8% over the revenue forecast at existing rates. The revenue requirement from the major customer classes is an increase of 9.6% over the revenue forecast at the existing rates. (p.45)

The Board considers that it is appropriate for the 2006/07 year that each class have a revenue to cost ratio of at least 0.95. (p.46)

The Board is of the view that it is also important to lower the revenue to cost ratios for those classes that have ratios significantly above 1.05. (p.46)

The one class with a revenue to cost ratio greater than 1.05 that will not receive a rate decrease is General Service II. This class will have a modest increase of 5.38% which will move its rates more in line with the rates for General Service I. (p.46)

We suggest that DISCO apply in the early fall of this year for approval of new rates for the 2007/08 year. Provided that Government accepts the Board's recommendations for changes in legislation discussed elsewhere in this decision, it could be an abbreviated proceeding. This abbreviated hearing will allow the Board to move all classes closer to unity. If the legislative changes recommended are accepted, then the 2008/09 rate hearing could begin during the winter of 2007 and allow a review of all the costs of the utility including those related to GENCO and the PPAs. At that time the Board will, as a priority, move those classes with a revenue to cost ratio above 1.05 aggressively towards unity. (p.48)

The process of rate design involves the selection of the basic rate structure and the values of parameters and prices used in that structure. (p.49)

The Board agrees that a flat rate with an appropriate service charge would better meet the design goals of reducing intra-class subsidy and providing better marginal cost information to customers. (p.51)

The Board therefore approves a residential rate in which: (p.52)

1. The service charge remains at $17.74 per Billing Period for urban residential customers, and $19.44 per Billing Period for rural and seasonal residential customers;
2. The size of the first block of energy is set at 1000 KWh per Billing Period;
3. The 1st block price is set at 9.2 ¢ per KWh; and

4. The remainder, or run-out, price is set at 8.6 ¢ per KWh.

There was consensus that the two classes, General Service I and General Service II, should be merged over time. The Board continues to believe that it is appropriate, at this time, to maintain two separate General Service classes. The Board approves the following rate structures for the General Service classes. (p.59-60)

	General Service I	General Service II
Service charge	$20.00	$20.00
Demand charge		
1st 20 KW	no charge	no charge
Balance	$8.78/KW	Lessor of $5.15/KW Or $0.02575/KWh
Energy Charge		
1st 5000 KWh	$.0825/KWh	$.0900/KWh
Balance	$.0725/KWh	$.0825/KWh

Small Industrial Class: The Board approves the following rates. (p.60)

Demand charge: all kW	$5.49/KW
Energy charge:	
1st 100 KWh/KW	$0.1059/KWh
Balance KWh	$0.0498/KWh

Large Industrial Rates:

The revenue requirement approved by the Board for the large industrial class for 2006/07 represents an increase of 15.36% over existing rates, subject to adjustment for the capital contribution from sales of surplus/interruptible energy. (p.60)

Wholesale Rates:

The revenue requirement approved by the Board for the wholesale class for 2006/07 represents an increase of 5.69% over existing rates, subject to adjustment for the capital contribution from sales of surplus/interruptible energy. (p.62)

Water Heater Rental:

The revenue requirement for water heater rentals as approved by the Board for 2006/07 represents a decrease of 16.66% to the revenue that would be provided by the existing rates. The Board orders DISCO to reduce its water heater rental rates by 16.66%. (p.63)

Street Lights and Unmetered:

The revenue requirement for street lights and unmetered service, as approved by the Board for 2006/07, represents a decrease of 10.05% to the revenue that would be provided by the existing rates. DISCO is ordered to reduce its rates for these services by 10.05%. (p.63)

Connection Charges:

The Board approves the connection charges as proposed by DISCO**.** (p.63)

All of the changes in rates, as approved by the Board in this decision, are effective as of August 1, 2006.

The Board believes that if Disco adopts a policy to come before the Board on a regular basis, filing updated and complete information, then the time expended and costs incurred because of regulation will diminish dramatically. (p.67)

NB Power Operating Results 1994 to 2005

Reserve accounts, referred to at the hearing as “rainy day accounts”, had been established and accumulated over many years and were approved by the Board. They had a balance, in total, in excess of $169 million. They were collapsed and the balances in the accounts were used to reduce losses in 1994/95, 1995/96 and 1996/97. NB Power eliminated the accounts without requesting approval from this Board. (p.68)

The Board has accumulated the results reported by NB Power and the changes in the regulatory deferral accounts and these are shown in Appendix E. (p.69)

The State of the Electricity “Market”:

The Board concludes that:

1. The required conditions laid out in the White Paper for a competitive market have not been met.
    - (a) The Crown utility’s generation portfolio has not been broken up.
    - (b) The province’s transmission interconnections with adjacent markets have not been significantly increased, and no study has been made to support the notion that the proposed 2nd tie-line to New England will be sufficient to permit a competitive market in New Brunswick.
    - (c) A Regional Transmission Organization (RTO) has not been established.
    - (d) The Non-Utility Generator contracts have not been conveyed to a distribution company, nor have they been restructured to allow the resources to compete in the New Brunswick market.
    - (e) The likelihood of the transmission and generation companies acting independently is put in question because of their common Board of Directors.

2. The structure of the PPAs confer “an inherent competitive advantage relative to new entrants” to GENCO through the requirement that DISCO pay all of GENCO’s fixed costs.

3. The current regulatory regime is not adequate to protect the interests of New Brunswick’s electricity users in the absence of a competitive market. Boards normally have the power to investigate customer complaints of regulated monopolies and impose remedies as required. This Board has just such authority in respect of both the natural gas distribution utility and the electric transmission utility it regulates. Similar authority was not granted in respect of DISCO, and the Board cannot initiate a rate review despite the clear policy intention that it should be able to do so.

4. The mechanism used to handle stranded costs introduces an unnecessary barrier to market development. The Act places the sole discretion for initiating a hearing into stranded costs in the hands of DISCO. The Board is unable to order such a hearing, and DISCO’s customers are unable to initiate a hearing without giving notice of their intent to leave standard service. Customers cannot make a reasonable determination as to whether or not they should leave standard service until they know the stranded cost implications of their departure, and they cannot know those costs until the hearing is held. This is clearly a significant and unnecessary impediment to the development of the market. (p.70-73)

In fact, GENCO is an unregulated monopoly supplier of electricity in New Brunswick. (p.73)

The Board finds no basis in law or policy to justify its consideration of the notion of a “level playing field” between different energy sources in setting electricity rates. (p.73)

There are three power purchase agreements between DISCO and its affiliates.

The COLESONCO Tolling Agreement.

The NUCLEARCO Energy Purchase Agreement.

The GENCO Vesting Agreement.

Together, these three agreements are responsible for 1.028 billion dollars (approx. 80%) of DISCO's costs. (p.75)

While these agreements define DISCO's costs, there is no mechanism in place to ensure that they fairly reflect the actual costs of these affiliates. (p.75)

The Non-Utility Generator (NUG) contracts are contracts for the supply of power and energy from non-utility generators in New Brunswick. The vesting PPA requires that fuel consumption for the NUG plants be estimated using the modeling assumption that all of the NUG plants are dispatched on a must-run basis. If all of the NUG plants were not designated "must-run", the fuel volume and cost estimates would be lower and the Board would reduce the revenue requirement for the test year. (p.76-77)

DISCO filed confidential evidence indicating that fuel costs would be substantially lower if the natural gas units were dispatched in economic merit order. The net benefit to DISCO in this circumstance would be a savings of a substantial sum of money. (p.78)

It is important to note that the vesting agreement requires DISCO to pay the fixed costs associated with GENCO's assets. This means that the long-term financial risks associated with owning the generation assets is borne by DISCO and its customers. (p. 78)

Further, since DISCO assumes this risk, normally the most significant risk borne by a generator, it is reasonable to expect that DISCO would obtain a much larger share of the export benefits than GENCO. (p.79)

Insurance:

It appears that DISCO's customers' bear risks that the White Paper anticipated would flow to the generation plants' investors. (p.79)

The difference between the reasonably expected production capacity and DISCO's entitlement is equivalent to some 690 MW of production capacity that DISCO pays for but GENCO is free to sell on the open market. (p.83)

DISCO is required to sell capacity to GENCO at a price lower than GENCO charges DISCO for the same capacity. DISCO's customers appear to subsidize GENCO by $6.5 million for the test year. (p.84)

The Board also notes that the payments by DISCO to GENCO are adjusted upwards annually to compensate for general inflation, but no such adjustment is made to the payments from GENCO to DISCO. Such asymmetrical treatment is not appropriate. (p.85)

If DISCO were to reduce its peak demand while holding its energy sales constant by load shifting through time-of-use rates, it would be reasonable for it and its customers to capture the benefit of that demand reduction by reducing its capacity nomination under the PPA. The net result would likely be that DISCO would pay the New England price to GENCO for the energy shortfall. Such a disincentive for good asset utilization is not in the best long-term interests of either DISCO's customers or the shareholder. It is also inconsistent with the direction established in the government's White Paper. (p.85)

The NUCLEARCO PPA was structured so that DISCO pays it a simple price, in $ per MWh, for energy delivered. This price clearly includes compensation for both fixed costs and variable costs. In the event of a shortfall by NUCLEARCO, GENCO will make it up using capacity that is already fully paid for by DISCO, and charge a price that includes an allowance for capacity, effectively double billing DISCO for capacity. (p.87)

The pricing provisions of the Point Lepreau PPA shortfall clause appear to be inconsistent with public policy goals and raise a reasonable apprehension of unfair treatment for DISCO's customers. (p.88)

The Board finds that section 156 is spent and of no force and effect in respect of any applications following delivery of the present decision. (p.90)

The Board cannot initiate a hearing into exit fees. (p.93)

Actual production by GENCO's hydro-electric facilities during the first eight months of the 2005/06 year was 655.6 GWh higher than average, as water flows were significantly greater than average. This extra production, in only eight months, was approximately 25% more than the normal full year production of 2654 GWh. Hydro production continued above normal and at the end of eleven months, the extra production had resulted in a payment to DISCO from GENCO of $21.3 million which was based on the incremental cost for in-province energy only. If the incremental cost had been based on the most expensive energy produced by GENCO, including export sales, the payment to DISCO would have been $71.8 million or $50.5 million more. (p.94)

The Board, in its decision dated May 22, 1991, concluded that the principle of adjusting NB Power's annual operating results so as to equalize the operating performance of the nuclear and hydro units was appropriate. (p.96)

The Board considers it unlawful that the regulatory reserve accounts approved by it in the early 1990s were eliminated without its approval. (p.96)

The Board is of the opinion that it has the authority to establish a hydro adjustment or deferral account for the test year 2006/07. However, the Board is not going to do so at this time. (p.97)

The Board directs DISCO to file with the Board a proposal outlining how such an account could be established together with suggested terms and conditions for its operation. (p.98)

The Board is concerned that the Act does not contain an express provision allowing it to review proposed capital expenditures of DISCO. (p.98)

Most of the intervenors, both formal and informal, agreed that the NB Power group of companies today still operates as a vertically integrated utility. (p.99)

Most of the intervenors submitted that there is no competitive market for electricity in New Brunswick and further argued that until such time as there is a competitive market, the NB Power group of companies should all be fully regulated by the Board. (p.100)

The Board strongly recommends to Government that a complete review of the Act occur immediately. One of the objectives of such a review would be to provide the Board with normal regulatory tools including general supervisory powers over the NB Power operating companies. (p.100)

The Board makes specific recommendations in respect of amendments to the Act. (p.100)

4. REVENUE REQUIREMENT AND RATES FOR 2006/07

Purpose of the Hearing:

The principal purpose of the hearing was to determine the revenue requirement for the financial year ending March 31, 2007. Having determined the overall revenue requirement, the Board must then allocate the revenue amongst all classes of customers, then set the actual rates to be charged to those customers.

Section 156 of the Act restricted the Board in its ability to properly review many of the costs that make up the revenue requirement. This is discussed in detail later in this decision. The Board must stress that out of the $1.3 billion revenue requirement proposed by DISCO it was forced to accept almost $1.1 billion as necessary due to Section 156. In other words, the Board could not, for this hearing, make any adjustments to costs that represent over 80% of the total expenses.

Rates for Third Party Pole Attachments:

Poles are essential for the delivery of electricity and communications to NB homes and businesses. DISCO and Aliant jointly own and control over 300,000 poles in the province. A typical 40 ft. hydro pole includes a 2 ft. space allocation for communication attachments. Third parties that use any of this space pay an annual pole rental rate. In 1967 NBP entered into a joint use agreement with Aliant for sharing the poles. That agreement was replaced in 1996 with a joint sub-agreement to include third party pole attachments. Under that agreement, Aliant administered the communication space for the poles and charged Rogers, a cable service provider, a pole attachment rate of $9.60

On January 30, 2004, DISCO gave Aliant a 30-day termination notice of their Third Party Attachments Sub-Agreement. In April, DISCO notified Rogers that it was re-assuming administrative control over its poles and began invoicing Rogers at the increased rate of $18.91 as of May 1, 2004. Rogers was notified that the annual attachment rate would increase to $23.50 on April 1, 2005 and to $28.05 on April 1, 2006. DISCO has requested approval of an annual rate of $30.61. Rogers, in its evidence, proposed a rate of $13.26/pole annually.

Rogers attempted to negotiate an agreement with DISCO on its proposed rate and failed. Rogers applied for and was granted formal intervenor status in the current application. The Board heard arguments form the parties on its authority to set rates for third party pole attachments and ruled, on October 27, 2005, that its jurisdiction included setting attachment rates. A copy of this ruling is attached as Appendix D.

The Board has carefully considered the detailed evidence, the testimony and the final arguments of the parties. There was little agreement between the parties on space allocation, wire sag, pole numbers, embedded costs, vegetation management and productivity losses.

After careful consideration, the Board finds that quality and accuracy of the financial and operational information used by the parties is not sufficient for rate setting. For example, the total number of poles recorded in DISCO's accounting records of 362,089, varies significantly from the number of poles recorded in its geographic information system estimated at 343,000. Costing data numbers from 1964 to 2005 identifies the number of poles as 339,241. The number of joint use poles, was estimated by Mr. O'Hara to be approximately 291,085 however the number of poles used by DISCO in calculating its embedded costs was 309,091.

The Board agrees that all users should bear a portion of the joint and common costs incurred to provide their service. However, the Board rejects the specific rate proposals of both DISCO and Rogers due to the nature of the underlying data. Based on the evidence placed before it and the decisions in other jurisdictions, the Board believes that an annual rate of $18.00 per pole for the test year is appropriate. The Board directs DISCO to undertake a study into its poles, equipment and related costs that will be used to review attachment rates at a future hearing. DISCO is instructed to consult with Board staff, Rogers and the Municipals to determine the scope of the study.

The Board recognizes that by approving this rate DISCO will receive $1.3 million less in revenue from pole attachments. This will decrease the miscellaneous revenue forecast from $23.6 million to $22.3 million.

Purchased Power Expense:

DISCO does not generate any electricity and must purchase all the energy and capacity required to serve its customers. It does this through various power purchase agreements (PPAs). The cost associated with the PPAs for 2006/07 is estimated to be $1.028 billion. That amount was verified for reasonableness by La Capra Associates, an independent expert retained by DISCO. For the purposes of this hearing, Section 156 of the Act requires the Board to accept any expenditures arising from the PPAs as necessary for the provision of the service. The Board must therefore accept $1.028 billion as the expense for purchased power for 2006/07.

Transmission Expense:

DISCO forecast a cost of $61.6 million for transmission services in 2006/07. This cost is based on the rates contained in the Open Access Transmission Tariff (OATT) administered by the NBSO and approved by this Board. No party took exception to this expense and the Board will accept the cost for 2006/07 as forecast by DISCO.

Operations, Maintenance & Administrative Expenses:

(i) Amount for 2006/07

The forecast OM&A expense for 2006/07 is $98.9 million. This total includes $27.7 million of expense that results from service agreements with affiliated companies. Section 156 states that these expenditures must be accepted as necessary and not subject to adjustment by the Board in this hearing.

Of the remaining $71.2 million, labour and benefits amounts to $48.0 million or approximately 67%. DISCO has reduced the number of its employees by 20% and is confident about this expense forecast. No evidence was provided to indicate that the figure of $48.0 million was overstated.

Mr. Hyslop recommended *"that the Board reduce OM&A component of the revenue by five percent or $5 million. If nothing else this will serve as an incentive to accelerate the efficiency improvements frequently touted during the testimony…"*. (Transcript, p. 6157)

The Board appreciates and shares Mr. Hyslop's concern with controlling the OM&A expenses. However, no specific evidence was presented to support the reduction proposed by Mr. Hyslop. The Board expects DISCO to pursue ways to reduce OM&A expenses. The Board will, for 2006/07, accept an amount of $98.9 million for OM&A expenses.

(ii) Energy Efficiency & Demand Side Management

Energy Efficiency refers to the efficient use of energy by consumers. Demand Side Management (DSM) refers to energy conservation and load shape modifying activities that are undertaken in response to a utility administered program. It includes the planning, implementation and monitoring of a utility's activities designed to encourage consumers to modify their patterns of energy usage, including the timing and level of electricity demand. It does not refer to energy and load shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards.

DISCO reduced its load forecast for 2006/07 by 82 GWh due to energy efficiency and conservation. Vibrant Communities Saint John (VCSJ) questioned DISCO about its DSM activities. It stated that some utilities in Canada had certain DSM programs designed to assist low-income households and that DISCO's load forecast for residential demand of 5008 GWh includes a reduction of only 36 GWh for DSM and energy efficiency improvements. VCSJ stated its concern that DISCO's staff of 7 energy advisors, who assist the residential and general service classes, were insufficient in number to deliver an efficient program of demand side management.

VCSJ stated its opinion that late payment charges were not the result of negligent customers but rather resulted from customers falling behind on their winter heating bills in part due to the fact they live in older, inefficient homes. They recommended that DISCO's revenue from residential late payment charges be used to establish a specific fund that promotes energy efficiency in low income households. The fund could be developed and managed in cooperation with the New Brunswick Energy Efficiency and Conservation Agency.

The Board believes that energy efficiency and DSM are topics that require further research by DISCO. The Board directs DISCO to undertake a review of Canadian utilities' energy efficiency and DSM programs including evaluation methods used to identify the cost benefits. This review is to be filed with the Board within six months of the date of this decision.

(iii) Customer Assistance Programs

VCSJ encouraged DISCO and the Board to consider establishing an arrears fund as an active measure designed to support low-income households. It was noted that the Salvation Army administers such a utility-financed program in Nova Scotia. Low-income ratepayers apply to the charitable organization for assistance to pay their overdue electricity accounts. VCSJ stated that there were other utilities across Canada that also offer programs or funding to assist low-income customers who experience difficulty paying for their energy consumption, particularly during the winter season.

The Board recognizes that the establishment of an arrears fund would impact DISCO's revenue requirement in any given year. As well, such a fund would require the development of new customer policies, funding and administration. The Board believes that the topic of establishing an arrears fund would be best canvassed during the hearing into DISCO's customer service policies. This hearing should also include a discussion on the Board's authority to order DISCO to implement such a fund.

(iv) Credit & Collections Procedures

During 2004/05 DISCO scheduled 12,197 accounts for disconnection due to non-payment, of which 5,100 disconnects were actually made. In the same year DISCO entered into 106,804 financial arrangements, virtually all of which were with residential customers. Despite the large number of financial arrangements DISCO is not able to determine which customers require habitual collection activity.

The evidence indicates that 660,000 late payment/disconnect notices are sent annually (approximately one for every 6 bills issued). Ninety percent of such notices are triggered by the collection process based on criteria such as (1) the age of the receivable, (2) the amount of the arrears, and (3) the customer's credit history. For low risk residential customers, the first reminder is sent 11 days after the due date, the second reminder at 21 days after the due date and a final reminder at 31 days after the due date. A telephone contact is made at day 41 and a disconnection is scheduled at day 51.

Late Payment and Disconnect Notices sent in 2004/05 as a percent of bills sent were 6% for Newfoundland Power and 16% for Nova Scotia Power as compared to 17% for DISCO. Although the bad debt expense and number of employees dedicated to credit and collection for these other utilities are not on the record in this proceeding, DISCO should be aware of the best and most efficient practices in this area.

The Board is generally aware of certain credit and collections procedures used in other jurisdictions. Considerable work has taken place in Ontario since the OEB's "Retail Settlement and Distribution System Codes" became effective in February, 2004.

The Board is also aware that some jurisdictions issue different "reminder" notices depending on a customer's credit score. For instance, in Colorado, Excel Energy's customers with a "good" credit score receive a reminder letter 33 days after their due date, a notice of disconnection on day 64 and the disconnection action begins on day 74. Customers who do not have a "good" credit score do not receive a reminder letter at all, they are sent a notice of disconnection on day 33 and the disconnection is initiated on day 41.

The Board wonders if issuing 660,000 late payment/disconnect notices is serving a useful purpose if such notices are not being targeted in a way that reflects the customer's regular payment practice. It may serve more as an aggravation to many customers than as an effective method of enforcing credit policy. The Board has concerns that DISCO does not track the payment records in a way that can identify habitual late payment practices. This would assist in assessing the effectiveness of introducing deposit requirements from those who demonstrate poor credit worthiness on an on-going basis.

Initiatives should be undertaken to find ways to evaluate staffing levels. Modifications of the collection policies and procedures could reduce payment problems and reduce the associated costs that must be recovered from customers.

DISCO is directed to undertake an investigation into current utility practices relating to credit and collections. It is to file its findings prior to the hearing on Customer Service and Policies. The Board directs DISCO to discuss this matter with Board staff prior to undertaking this investigation.

(v) Uniform System of Accounts

A Uniform System of Accounts (USOA) is a system for recording and reporting information for use in the preparation of financial and operational reports. Such systems include basic definitions, accounting and operational descriptions and instructions. They provide a standard or uniform methodology for recording and reporting information and have been developed and adopted by industry and regulators.

A USOA is the base that provides quality information for benchmarking purposes, both year over year and between utilities. It provides information recorded in a clearly defined set of accounts that is transparent to all users and not changed without the regulator's approval. In many jurisdictions USOAs have been developed and are required to be used by electric, gas, water and sewage utilities. In Canada, both Alberta and Ontario have adopted USOAs for use by utilities in the electricity and natural gas sectors.

The Board believes that parties would have been better served had a USOA been available. The Board is aware that the Canadian Electrical Association is developing, with its members, a USOA for use by its members. The Board will require DISCO to implement a USOA. DISCO is ordered to work with Board staff to propose an appropriate USOA and a time period for its implementation.

(vi) Capital Investment Criteria

The majority of "Distribution" work does not lend itself to individual cost benefit analysis as it is typically large volume, small dollar value in nature, with no single proposed additions greater than $250,000. Ms. MacFarlane confirmed that 90% of investment under the categories of asset reliability and load growth is not subject to financial analysis incorporating the cost of capital. Ms. MacFarlane further stated that DISCO's own Board is not satisfied with the existing degree of rigor relating to capital investment decisions, and has asked that the process be changed prior to the preparation of the 2007/08 budget.

The response to DISCO (PUB) IR-229 showed that over $2,800 could be saved by the immediate replacement of four vehicles. However, during the hearing, it was identified that the analysis did not take into account the cost of capital for acquiring the new vehicles. Adding in this financing cost would mean that immediate replacement would not be economic. Mr. Marois undertook to investigate the reason the analysis omitted financing costs.

The Board is concerned that something as fundamental as the cost of capital could have been omitted from financial analyses. It brings into question the extent to which good management practices may be lacking in other areas, which may increase costs to consumers.

The Board acknowledges that it is not normal to make an individual financial analysis on many distribution assets. However, these investments represent $30 million for 2006/07. The Board's view is that financial evaluations for "types" of repetitive investments should be documented on a periodic basis. This should form part of a comprehensive corporate "Capital Justification Criteria" manual, which would provide a one-stop source of information relating to the financial analysis for all capital expenditures.

The Board orders DISCO to compile a comprehensive Capital Justification Criteria Manual and file it with the Board within six months of the date of this decision.

Amortization Expense:

DISCO forecast amortization expense for 2006/07 of $43.4 million. No party took exception and the Board will accept the amount for 2006/07. The Board retained Mr. Kennedy, an expert on amortization practices, who identified various ways that DISCO's approach differs from that used by the majority of North American utilities. DISCO acknowledged that improvements could be made and agreed to undertake a study into this matter. The Board appreciates DISCO's intention to complete a study on its amortization practices and directs that it be filed with the Board within six months of the date of this decision.

Taxes, Excluding Payments in Lieu of Income Tax:

Taxes, excluding payment in lieu of income tax, were estimated at $13.4 million for 2006/07 by DISCO. There were no objections and the Board will accept this amount.

Interest Expense:

On October 1, 2004, HOLDCO transferred to its operating subsidiaries the business and net assets of the business units that operated the Point Lepreau nuclear station (NUCLEARCO), the other power generating facilities (GENCO), the high voltage transmission assets (TRANSCO) and the distribution and customer service operations (DISCO). With the exception of TRANSCO, the transfers were effected at the recorded net asset values of the business units in exchange for promissory notes issued to HOLDCO equal to the value of the net assets transferred. In the case of TRANSCO, $140 million of Class B non-voting shares were issued to HOLDCO together with promissory notes for the balance of the net asset values received.

DEBTCO is a crown corporation that reports to the Minister of Finance. On October 1, 2004 HOLDCO transferred to DEBTCO all the promissory notes it had received from its subsidiaries and the Class B non-voting shares of TRANSCO in exchange for the assumption of all the debt obligations of HOLDCO to the Province. At the date of restructuring, NB Power had accumulated a deficit of $187 million. The deficit was eliminated by DEBTCO issuing to HOLDCO equity in the form of contributed surplus of that amount.

The effect of these transactions is that DISCO will be responsible for retiring $661 million of the debt obligations of the Province that were outstanding on September 30, 2004. NB Power's total debt obligations at that date were over $3.5 billion and were referred to during the hearing as “legacy debt”.

DISCO makes interest payments on this debt to DEBTCO as required by the terms of the underlying debt instruments. These payments are shown as an expense on the income statement and are part of the revenue requirement proposed by DISCO for 2006/07.

DISCO also makes principal payments to DEBTCO as required. These payments are not an expense on the income statement and are not part of the revenue requirement in 2006/07. Each year DISCO pays DEBTCO 1% of the original principal amount of each debenture. At the time of maturity of each debenture, DISCO will pay the remaining principal amount. These payments will be financed by cash from operations or by issuing new debt.

The Board believes that it is the intention of the Province to have DISCO, over time, replace its part of the legacy debt guaranteed by the Province with debt guaranteed by DISCO. This replacement of one guarantee for another will have little, if any, effect on DISCO's revenue requirement.

DISCO has forecast an amount of $39.4 million as its interest expense for 2006/07. This is the sum of the interest payments on debt owed by DISCO to finance its business in 2006/07. The Board will accept this amount.

Payments in Lieu of Income Taxes (PILT):

The Act includes the following provisions:

> "***37****(1) During the period that the Corporation or a subsidiary of the Corporation incorporated pursuant to subsection 4(1) is exempt under subsection 149(1) of the Income Tax Act (Canada) from the payment of tax under that Act, it shall pay to the Finance Corporation in respect of each taxation year an amount equal to the amount of the tax that it would have been liable to pay under that Act if it were not exempt.*

> ***37**(2)During the period that the Corporation or a subsidiary of the Corporation incorporated pursuant to subsection 4(1) is exempt under subsection 10(1) of the New Brunswick Income Tax Act from the payment of a tax under that Act, it shall pay to the Finance Corporation in respect of each taxation year an amount equal to the amount of the tax that it would be liable to pay under that Act if it were not exempt.”*

The definitions in the Act indicate that "Corporation" means the New Brunswick Power Corporation as continued under the Business Corporations Act under the name HOLDCO. DISCO is a subsidiary of HOLDCO and thus is subject to PILT.

Sections 37(1) and 37(2) above clearly state that a subsidiary shall pay an amount equal to the amount of the tax that it would have been liable to pay under the relevant income tax acts if it were not exempt.

Note 3j of DISCO’s financial statements for the period ended March 31, 2005 states:

> *“The Corporation is required to make special payments in lieu of taxes to the NBEFC. Total special payments in lieu of taxes consist of:*
>
> - *An income tax component based upon **accounting net income** multiplied by a rate of 35.12%. [Emphasis added].*
>   - *A capital tax component based upon the large corporation tax rules contained in the federal and provincial income tax acts.”*

The adoption of this accounting policy is not in compliance with the method of calculation required by the Act.

DISCO calculated PILT on the basis of accounting income and not taxable income.

Under questioning by Mr. MacNutt concerning the calculation of PILT, Ms. MacFarlane stated as follows:

> *"In exhibit A-50 under the direct evidence of Lori Clark, tab 4, which is actually my evidence, on page 7 … Lines 7 through 12 speak to the calculations, showing the underlying rates which are specified by the Income Tax Act and the calculations. The calculation is done on the basis of accounting income and there is no allowance for any temporary differences in asset base between what might be capital cost allowance or undepreciated capital cost in the Income Tax Act, and the accounting value of the assets."*
>
> *There was an IR that addressed that, PI IR-19 and 55. And this was a measure that was agreed to with EFC to avoid legal and accounting costs that would be associated both with set up and maintenance of the dual tracking of asset values and the cost of establishing initial tax values which would require rulings from Canada Revenue Agency. So the tax is done on the basis of accounting income and that is the amount that is remitted to EFC.*
>
> *We did, by the way, seek advice from Deloitte & Touche about the nature and cost associated with tracking separate asset values. Their advice was that we would require three to four tax accountants, perhaps tax assistants in our legal department, that there would be external consulting costs annually that would be very expensive. There would be very expensive systems costs associated with putting in place records that would track the tax cost of assets*." (Transcript. p. 3759-60)

The Board notes that there are other provisions of the federal and provincial income tax acts in addition to the temporary differences related to capital assets, that would also require consideration in determining the current tax liabilities of DISCO under section 37 of the Act. Such provisions might have a significant effect on the calculation of special taxes in lieu of income taxes and thus on the cash flow of DISCO.

In the opinion of the Board, the response of DISCO to the legislation is unsatisfactory for the following reasons:

a) The Act is clear as to the basis of the required calculation of PILT.

b) Pursuant to the Act, the Board has regulatory authority over DISCO and should have been advised of the perceived difficulties in this matter, so that a ruling could have been given before the hearing.

c) The greatest difficulty in this matter appears to be the value at which assets would be recorded for income tax purposes. The Board is of the opinion that the book values at which assets were transferred to DISCO would have been an acceptable basis for calculating capital cost allowances and would be prepared to so rule.

d) The Board considers that the cost of calculating special payments under this ruling would not be as onerous as indicated by Ms. MacFarlane in her evidence.

e) Companies operating in a competitive marketplace and subject to income tax make every effort to minimize their overall tax liability.

The Board orders DISCO to formulate a strategy that would utilize all aspects of the applicable income tax acts in order to minimize PILT.

Net Income:

DISCO forecast a net income of $14.4 million for 2006/07. This amount was effectively based on two key assumptions. The first assumption was a capital structure of 57.5% debt and 42.5% equity. The second assumption was a return on equity of 10%.

The evidence indicated clearly that for 2006/07, the only equity that DISCO might have would be any retained earnings generated by the end of the 2005/06 financial year. There was no forecast of any contribution of share capital in 2006/07 and DISCO did not request a deemed capital structure for 2006/07.

The Board therefore does not consider it appropriate to use the deemed equity method to establish the forecast net income of DISCO for 2006/07. The Board considers that use of the interest coverage method is more suitable.

In its decision of May 22, 1991, the Board stated that the most important ratio for NB Power to consider was the interest coverage ratio. Furthermore, it considered that a target ratio of 1.25x coverage was appropriate for NB Power and would be consistent with other Canadian utilities.

DISCO's proposed net income of $14.4 million requires an income before interest expense of $62.6 million. This level of income together with the forecast interest expense of $39.4 million produces an interest coverage of 1.59x. The Board considers this coverage to be excessive and will reduce the revenue requirement as discussed below.

This Board has, as does each regulator when setting rates, a dual responsibility. First, it must set just and reasonable rates that are fair and equitable to all the customers of the utility. Second, it must allow the utility to earn a return on its investment sufficient to allow it to attract capital and thus continue to offer the service for which it has the monopoly.

We believe that setting rates at a level that will permit the utility, over time; to earn an interest coverage ratio of 1.25x will allow it to ultimately raise capital without a Government guarantee. An interest coverage ratio of 1.25 for 2006/07 requires that the total revenue requirement be set at $1.2947 billion. The total revenue comes from sales to the major customers classes (such as residential), from sales of interruptible and surplus energy and from various miscellaneous services. The amount that must be recovered from the major customer classes is calculated as follows:

Total Revenue Requirement			1,294.7
Less:	Interruptible/Surplus	62.0	
	Miscellaneous (as adjusted)	22.3	
		84.3	(84.3)
Net Revenue from Major Customer Classes			1,210.4

Fairness suggests that the target for each class of customers should be a revenue to cost ratio of 1:1. In other words, the revenues from each class should equal the costs of providing service to that class.

The Board has prepared the Table A to show the changes in revenue necessary to provide an interest coverage of 1.25 and to have a revenue to cost ratio of 1:1 for each class.

TABLE A			
MAJOR CUSTOMER CLASS	REVENUE AT EXISTING RATES	CLASS REVENUE REQUIREMENT (1.25 Interest Coverage and 1:1Revenue to Cost Ratio)	% CHANGE NECESSARY
Residential	455.8	543.5	19.2%
General Service 1	103.9	88.5	(14.8%)
General Service 2	111.5	102.8	(7.9%)
Small Industrial	42.3	43.9	3.8%
Large Industrial	262.3	319.0	21.6%
Water Heaters	15.0	10.4	(30.6%)
Street Lights / Unmetered	19.9	12.0	(39.7%)
Wholesale	87.8	90.3	2.9%
TOTAL	1,098.5	1,210.4	10.2%

Table A shows that the required increase in revenue would be $87.7 million for the Residential class and $56.7 million for the Large Industrial class. The Board considers that increases of this size in one year are too drastic, particularly in light of the following comments.

The Board could not challenge over $1 billion of DISCO's costs during this hearing. The Board also has strong concerns about some of the data used in the cost allocation study underlying the customer class costs as set out above. For these reasons, we do not believe that we should set the revenue requirement for each class as indicated in Table A at this time. Accordingly, the Board feels that it must break with normal regulatory practice and set rates that will neither return the recommended interest coverage ratio of 1.25x nor target a revenue to cost ratio of 1:1 for each customer class.

The Board considers that an interest coverage ratio target of 1.10 is appropriate for 2006/07. This level of interest coverage results in a net income of $3.9 million.

Total Revenue Requirement:

The total revenue requirement for 2006/07 approved by the Board is $1.2887 billion as shown in Table B below. This represents an increase in the total revenue requirement of 8.8% over the revenue forecast at existing rates.

TABLE B

Calculation of Total Revenue Requirement for 2006/07

Purchased Power	$ 1,028.1
Transmission	$ 61.6
OM&A	$ 98.9
Amortization	$ 43.4
Taxes, Other than Income	$ 13.4
Interest	$ 39.4
Net Income	$ 3.9
Total Revenue Requirement	$ 1,288.7

This total revenue requirement is $6.0 million less than that required for a 1.25x interest coverage. The revenues from interruptible/surplus energy and miscellaneous services are not affected. This means that the revenue that must be recovered from the major customer classes is reduced to $1.2044 billion. This revenue requirement from the major customer classes is an increase of 9.6% over the revenue forecast at the existing rates.

Revenue to Cost Ratios:

The Board considers that it is appropriate for the 2006/07 year that each class have a revenue to cost ratio of at least 0.95. Establishing this minimum ratio will reduce inter-class cross-subsidies and allow rates to provide a price signal that will lead to more efficient use of electricity. The Board is of the view that it is also important to lower the revenue to cost ratios for those classes that have ratios significantly above 1.05. For this reason, the Board is approving rate decreases for the General Service I, Water Heaters and Street Lights/Unmetered classes. The one class with a revenue to cost ratio greater than 1.05 that will not receive a rate decrease is General Service II. This class will have a modest increase of 5.38% which will move its rates more in line with the rates for General Service I. Many parties recommended that the rates for the General Service classes be brought closer together and the Board agrees that this is appropriate.

Table C shows the revenues required from each customer class with an interest coverage of 1.10, the revenue to cost ratios that the Board has approved for 2006/07 and the revenue requirement of $1.2044 billion from the major customer classes.

TABLE C						
Class	**Revenue at Existing Rates**	**Revenue Requirement at 1.1 x Interest Coverage & 1:1 Revenue/Cost Ratio**	**Revenue/Cost Ratio Existing**	**Revenue Approved by Board**	**Revenue/Cost Ratio at Approved Rates**	**Change Necessary**
Residential	455.8	540.7	0.844	515.3	0.953	13.05
General Service I	103.9	88.4	1.176	102.0	1.154	(1.83)
General Service II	111.5	101.7	1.096	117.5	1.155	5.38
Small Industrial	42.3	43.9	0.967	43.8	0.998	3.55
Large Industrial	262.3	317.5	0.826	302.6	0.953	15.36
Water Heaters	15.0	10.4	1.437	12.5	1.202	(16.66)
Street Lights/Unmetered	19.9	11.9	1.674	17.9	1.504	(10.05)
Wholesale	87.8	89.7	0.978	92.8	1.035	5.69
TOTAL	1,098.5	1,204.4	0.912	1,204.4	1.0	9.64

We suggest that DISCO apply in the early fall of this year for approval of new rates for the 2007/08 year. Provided that Government accepts the Board's recommendations for changes in legislation discussed elsewhere in this decision, it could be an abbreviated proceeding. This abbreviated hearing will allow the Board to move all classes closer to unity. If the legislative changes recommended are accepted, then the 2008/09 rate hearing could begin during the winter of 2007 and allow a review of all the costs of the utility including those related to GENCO and the PPA. At that time the Board will, as a priority, move those classes with a revenue to cost ratio above 1.05 aggressively towards unity.

Rate Design

Introduction:

In allocating DISCO's revenue requirement between the various classes of customers, the Board is principally concerned with inter-class equity, *i.e.* ensuring that each class of customers pays its fair share of DISCO's legitimate costs. In rate design, the principal concern is intra-class equity, ensuring that customers pay their fair share of the costs allocated to their class.

A second concern in rate design, and one that is not explicitly considered in the revenue allocation process, is economic theory related to economically efficient pricing. This theory suggests that the price a customer pays for the last KWh of electricity they purchase each month (their marginal consumption) should equal the cost of providing that KWh of electricity (the marginal cost). When the marginal price and cost are equal, customers receive an appropriate price signal by which to adjust their consumption of electricity towards levels that are optimal from an economic perspective.[1]

[1] To the extent that the marginal price reflects the broader costs of electricity production and delivery, environmental and social costs and benefits, for example, the price signal provides an incentive to the customer to adjust their consumption towards levels that are more broadly optimal.

In addition to fairly allocating class costs amongst customers and providing for efficient price signals, the rate design must be such that the Board has a reasonable expectation it will provide the company with the revenue requirement allocated to the class. It also recognizes the common view that good rate-setting practice may require a series of incremental adjustments to existing rates to bring them in line with the principal objectives outlined above.

The process of rate design involves the selection of the basic rate structure and the values of parameters and prices used in that structure. Generally, more complex rate structures have greater information requirements and need more complex and costly metering equipment. DISCO currently offers four basic types of rates:

1. Energy metered rates, in which total energy consumption is the only measured quantity. This is the least expensive form of metering. All residential customers and smaller commercial/institutional customers are served under this type of rate.
2. Energy and non-coincident peak demand metered rates, in which total energy consumption and the highest rate of energy consumption (demand) in the billing period are measured. This uses metering equipment that is more expensive than the simple energy meter and requires that two pieces of data are recorded and processed. Larger commercial/institutional customers and industrial customers are served under this type of rate.
3. Interval-metered rates, in which each month is divided into a large number of small (5 to 15 minute) time intervals and the energy use in each interval is recorded. This metering equipment is the most expensive, particularly because it requires that large volumes of data must be stored and processed to compute the monthly bill. Customers connected directly to the transmission grid are served through interval meters, but only interruptible and surplus electricity purchases are billed using interval-metered data.
4. Un-metered rates, in which the energy use and demand can be accurately and reliably predicted by engineering analysis (traffic lights, for example). In this case no usage parameters are measured directly, but the assumptions underlying

the engineering analysis must be verified on installation and on an audit basis throughout the service life.

Residential Rates

Existing Rate

The existing residential rate design is a declining block energy price rate with a fixed service charge. It is characterized by four parameters:

1. The amount of the service charge. Currently this is $17.74 per Billing Period for urban customers and $19.44 for rural and seasonal customers
2. The size of the first block of energy. This is 1300 KWh per Billing Period. This is the maximum amount of energy that will be billed at the higher, 1st block price in any billing period.
3. The 1st block price. This is 8.37 ¢ per KWh. This is the cost per kilowatt-hour that is paid for energy in the 1st block.
4. The remainder, or run-out, price. This is 6.63 ¢ per KWh. Customers pay this lower price for any energy they use in excess of the 1st block.

Table 1

Illustration of Existing Rate Design Applied to Small and Large Monthly Bills for an Urban Customer.

Item	Description	*Units*	*Values*	
1	Season of Energy Use	-	Summer	Winter
2	Average Monthly Energy Use	KWh	750	3100
3	Service Charge	$ per mo.	$17.74	$17.74
4	1st Block energy used	KWh per mo.	750	1300
5	1st Block Energy Cost, @ 8.37 ¢ per KWh	$ per mo.	$62.78	$108.81
6	Excess Energy used	KWh per mo.	0	1800
7	Excess Energy Cost, @ 6.63 ¢ per KWh	$ per mo.	$0.00	$119.34
8	Total Bill Amount (sum of 3, 5 and 7)	$ per mo.	$80.52	$245.89
9	Average Energy Price	¢ per KWh	10.7	7.9

Table 1 illustrates the rate's application to two bills: an average summer bill (750 KWh), and an average winter bill for an electric space-heating customer (3100 KWh). The existing rate design, as illustrated in Table 1, results in an average price 10.7 ¢ per KWh during the summer and 7.9 ¢ per KWh for the space-heating customer in the winter, a 26% discount.

This 'discount for volume' is an inherent feature of the existing rate design that all parties to the proceeding recognized as inappropriate. It addition to being unable to provide sufficient revenue, the current rate charges large customers a significantly lower marginal price for electricity than small customers: 6.63 ¢ *vs.* 8.37 ¢ per KWh. This raises a question as to whether either price best reflects the marginal cost of electricity and under what circumstances it does so. The fixed service charge, which was characterized by one intervenor as among the highest in Canada, compounds the problem since it represents a larger proportion of small customers' costs.

Approved Rate

DISCO's Board of Directors has adopted a policy to move to a flat residential rate[2] by 2007 and an inclining block rate by 2010[3]. All intervenors supported the goal of moving to a flat rate structure for residential customers. The Board agrees that a flat rate with an appropriate service charge would better meet rate design goals of reducing intra-class subsidy and providing better marginal cost information to customers.

The Board considers that moving to a flat rate immediately would expose large residential customers to significant cost increases. Accordingly, on December 21, 2005 it ruled that DISCO should move to a flat rate over a three-year period. DISCO's proposed rate design is in compliance with that ruling. While the Board reaffirms that DISCO should not move to a flat rate immediately, its further and more detailed examination of

[2] A flat rate consists of a single price for energy during the billing period for all energy used during the period, and may or may not include a fixed service charge.

[3] An inclining 2-block rate, for example, sets the price of the 1st block of energy below the price of the run-out block.

the evidence has led it to conclude that a more rapid move towards a flat rate is appropriate at this time.

The Board therefore approves a residential rate in which:

1. The service charge remains at $17.74 per Billing Period for urban residential customers, and $19.44 per Billing Period for rural and seasonal residential customers;
2. The size of the first block of energy is set at 1000 KWh per Billing Period;
3. The 1st block price is set at 9.2 ¢ per KWh; and
4. The remainder, or run-out, price is set at 8.6 ¢ per KWh.

Table 2 illustrates the approved rate's application to the same two bills that were presented for the existing rate in Table 1. This rate design results in an average price 11.6 ¢ per KWh during the summer and 9.9 ¢ per KWh for the space-heating customer in the winter. The represent increases of 8.4% and 25.3%, respectively. The 'discount for volume' is reduced to 15% in the approved rate.

Table 2 Illustration of Approved Rate Design Applied to Small and Large Monthly Bills for an Urban Customer.				
Item	Description	*Units*	*Values*	
1	Season of Energy Use	-	Summer	Winter
2	Average Monthly Energy Use	KWh	750	3100
3	Service Charge	$ per mo.	$17.74	$17.74
4	1st Block energy used	KWh per mo.	750	1000
5	1st Block Energy Cost, @ 9.2 ¢ per KWh	$ per mo.	$69.00	$92.00
6	Excess Energy used	KWh per mo.	0	2100
7	Excess Energy Cost, @ 8.6 ¢ per KWh	$ per mo.	$0.00	$180.60
8	Total Bill Amount (sum of 3, 5, and 7)	$ per mo.	$86.74	$290.34
9	Average Energy Price	¢ per KWh	11.6	9.4
10	Increase over Current Cost (Table 1)	%	7.7	18.1

Reasons

Service Charges

The cost allocation and rate design study originally filed by DISCO was prepared in a customary manner and based on an allocation of costs to three categories: energy, demand, and customer. The Board also heard that the customer category represented an allocation of joint and common costs. After hearing evidence on the matter, the Board was concerned that the allocations between these categories were unduly subjective and sufficiently different from those previously filed to warrant further examination before they served as the basis for ratemaking. In its December 21, 2005 ruling, the Board therefore directed that the cost allocations used for the current rate setting proceeding be the same as those approved in its decision of April 15, 1992. The Board also ruled that

DISCO should re-examine their cost study and file a revised analysis at the time of the next full rate hearing.

Methods of allocating joint and common costs were examined, in detail, in the portion of the hearing dealing with third party attachments to DISCO’s poles. Evidence introduced in that matter clearly demonstrated that there are a number of legitimate ways in which joint and common costs can be allocated between users. In that portion of the hearing DISCO argued forcefully that the joint and common costs should be shared amongst all the services that are supported by these costs and proposed several ways to do so. Rogers Cable, the principle user of third party pole attachments under the tariff, agreed that they should cover a portion of the joint and common costs, but disputed the manner DISCO proposed to calculate both the amount of the joint and common costs and the fraction of those costs that should be charged to third parties. As noted elsewhere in this decision (p.29, *supra*), the Board recognizes and accepts the principle that all users should bear a portion of joint and common costs incurred to provide their service.

DISCO’s residential rate analysis indicates a monthly service charge of $23.04 per month. This indication serves as the basis for DISCO’s proposal to increase services charges for urban and rural/seasonal customers to $19.80 and $21.70, respectively.

Examination of the spreadsheet file containing Schedule 4.6 reveals 3 rows of data that were not printed in the paper submission. This additional information is provided in Appendix F. These provide detail relating to the three residential electricity uses considered by DISCO in developing its cost allocation and rate design, namely: electric space heating, electric water heating, and all other electricity uses. Each of these three residential uses clearly requires the poles, distribution wires, easements and transformers that contribute to the joint and common costs assigned to residential customers. Each also requires the use of the service drops and meters that serve individual customers. The Board would therefore expect that each of these uses would be assigned some portion of the joint and common costs of service and the direct customer costs in the cost allocation and rate design study. Such treatment would have been consistent with the evidence led by DISCO in the third party pole attachment matter.[4]

Column 8 of Schedule 4.6 in Appendix F makes it clear that DISCO does not take the same position when developing cost indications for residential rate making purposes. DISCO there assigns the full amount of joint and common costs and service costs to only one category of use, labelled “Residential All Other Uses”. Electric space heating and water heating bear none of the joint and common costs identified as necessary to serve those loads. It therefore underestimates the cost of serving space heating and water heating loads.

DISCO’s approach to the allocation of joint and common costs within the residential rate class is clearly inconsistent with and contradictory to its approach in respect of third party pole attachments.[5] It has the effect of overestimating the cost that should be recovered in the service charge and the 1st block of energy, and underestimating the cost that should be recovered in the run-out block. It thus supports the argument advanced by VCSJ that DISCO’s existing service charges are too high and that they should not be increased further.

For these reasons, the Board does not approve any increase in the service charges paid by residential customers. The method of allocating joint and common costs and individual customer service costs will be reviewed at the time of the next rate hearing.

[4] Assignment of joint and common costs and customer service costs equally between uses (1/3 each), in proportion to use (43% to space heating, 20% to water heating, and 37% to other uses) or in proportion to the costs for stand alone service would all have been more consistent with DISCO’s approaches to cost allocation for third part pole attachments.

[5] If it were applied in the case of third party pole attachments, it would result in Rogers being charged only the incremental costs associated with their use of the pole, an outcome that is clearly unacceptable to DISCO.

First Energy Block Size

DISCO proposed to increase the size of its 1st block of energy from 1300 KWh to 1400 KWh per Billing Period and this proposal was supported by EGNB. Doing so would increase the fraction of energy billed at the higher 1st block rate. It would also reduce the number of smaller customers that benefit from the lower run-out block price and preserve the benefits for the largest residential customers.

On examination, the Board heard that the 1st block size of the inclining block rate that is DISCO's ultimate goal may be "... between 8[00] and 900 kilowatt hours a month ..." (Transcript, p.5763). The Board notes that the 5 years of billing data filed by DISCO in this proceeding indicates that a 1st block size in this range would result in about half of DISCO's residential energy sales being sold in the 1st block and the other half being sold in the run-out block.

DISCO's proposed 1st block size of 1400 KWh would place about 67% of energy sales in the 1st block and only 33 % in the run-out block. The Board also understands that approximately 63% of residential electricity consumption is used for space and water heating, and that customers can use other fuels for those purposes. Basic lighting, refrigeration and water pumping loads are satisfied out of the remaining 37% of electricity use. There is no convenient substitute energy source for these purposes. These facts suggest that a rate structure based on a smaller 1st block size than DISCO has proposed will promote intra-class equity and appropriate pricing.

The proposed increase in the 1st block size is not approved for these reasons. The Board orders that the 1st block size be set at 1000 KWh per Billing Period.

First and Run-out Block Prices

Having determined that the service charges should remain the same and that the 1st energy block should be set at 1000 KWh per Billing Period, the Board set the 1st energy block and run-out block energy prices subject to the following considerations:

1. Prices be such that the approved revenue requirement could be earned over the 12 months of the test year,
2. Progress be made towards eliminating the declining block rate,
3. The subsidy or surcharge to customers should be as small as possible, subject to the concern for rate shock.

The method used to set these prices and evaluate the impact on customers is provided in Appendix F. The proposed rate would have resulted in cost increases ranging from 10.4% to 19.8% with a median increase of 12%. The approved rate results in cost increases ranging from 0% to 29.6% with a median increase of 10%. The impact of the approved changes to residential rates can be summarized as follows:

- Small customers that use electricity more-or-less uniformly throughout the year will experience the smallest increases in their bills.
- Large customers with usage that varies significantly over the year will experience the largest increases in their bills.
- Approximately 70% of customers experience smaller cost increases under the approved rate than they would have under the proposed rate. The remaining 30% of customers experience higher cost increases under the approved rate than they would have under the proposed rate.

Table 3 and Figure 1 provide summary data for the cost increases that customers will experience for monthly bills of different electricity consumptions.

---

[8] The impact of export sales revenue on in-province rates has been variously estimated:

Table 3

Impact of Approved Rate Increase on Monthly Bills of Different Sizes

Monthly Energy Use - KWh	Increase in Electricity Cost - %	
	Urban	Rural/Seasonal
0	0.0%	0.0%
100	3.2%	3.0%
200	4.8%	4.6%
300	5.8%	5.6%
400	6.5%	6.3%
500	7.0%	6.8%
600	7.3%	7.1%
700	7.6%	7.4%
800	7.8%	7.7%
900	8.0%	7.9%
1000	8.2%	8.0%
1100	7.8%	7.6%
1200	7.4%	7.3%
1300	7.1%	7.0%
1400	8.2%	8.1%
1500	9.2%	9.1%
1600	10.2%	10.1%
1800	11.8%	11.7%
2000	13.2%	13.0%
2500	15.8%	15.7%
3000	17.8%	17.6%
4000	20.3%	20.2%
5000	22.0%	21.9%

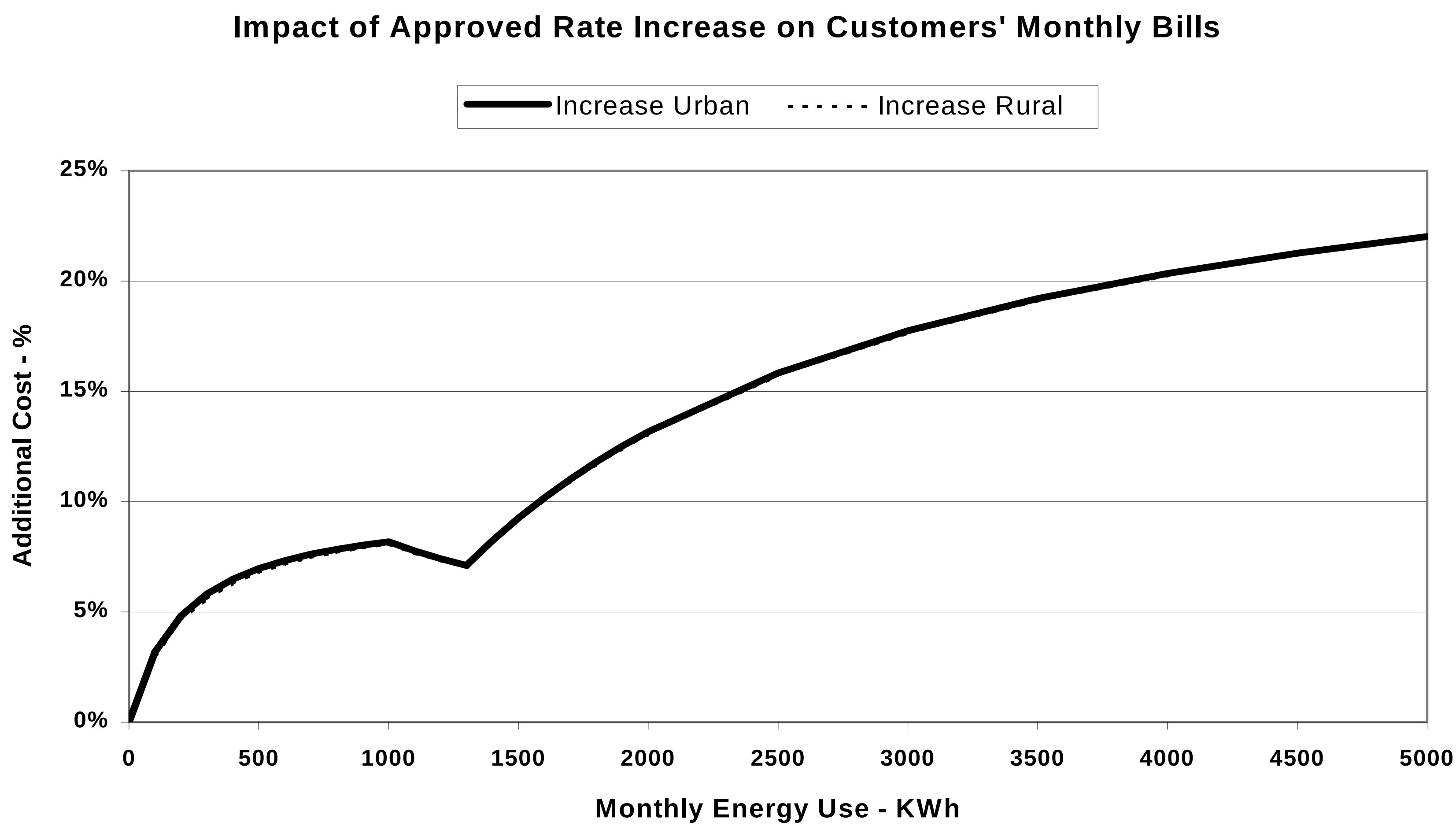


Figure 1 Increase in Monthly Residential Bill Arising from the Approved Rate

General Service I and General Service II Rates:

There was consensus that the two classes, General Service I and General Service II, should be merged over time. In its December ruling, the Board stated: *"A preliminary analysis of the usage data for the GS I and GS II customers indicates that there are distinct differences between the two classes. The Board considers that it is appropriate that the two classes be kept separate until further data is collected and more analysis occurs."* The Board continues to believe that it is appropriate, at this time, to maintain two separate General Service classes. DISCO will be conducting a study that will provide valuable information on the best way to proceed.

In the meantime, the Board is of the opinion that the rate structures for the two classes should be brought closer together. As well, the structures should provide better price signals and better reflect the underlying cost causation factors. The Board also believes that it is no longer appropriate to differentiate between the two classes on the basis of the use of electricity as the only source of energy.

Therefore, the Board approves the rate structures shown below for the General Service classes. Further, the Board directs that any existing or new customer who uses electricity for purposes not specifically covered under the residential, small and large industrial, street lighting or unmetered categories may choose either class of General Service. DISCO is further ordered to inform all existing General Service customers of their right to switch from General Service I to General Service II or vice versa.

	General Service I	General Service II
Service charge	$20.00	$20.00
Demand charge		
1st 20 KW	no charge	no charge
Balance	$8.78/KW	Lessor of $5.15/KW or $0.02575/kWh

Energy charge

1st 5000 kWh	$.0825/kWh	$.0900/kWh
Balance	$.0725/kWh	$.0825/kWh

Small Industrial Class:

The revenue requirement approved by the Board, for the small industrial class for 2006/07, represents an increase of 3.55% over existing rates. The Board heard no evidence that the current rate structure for this class is inappropriate and therefore directs that the increase be applied evenly. The Board therefore approves the following rates:

Demand charge: all kW $5.49/kW

Energy charge:

1st 100 kWh/kW	$0.1059/kWh
Balance kWh	$0.0498/kWh

Large Industrial Class:

The revenue requirement approved by the Board for the large industrial class for 2006/07 represents an increase of 15.36% over existing rates. The Board lacks sufficient evidence to support differential changes to the energy and demand components of the large industrial rate and therefore approves the following rates, subject to adjustment as noted below:

Demand Charge: $11.85 per KW of the Billing Demand per month.

Energy Charge: 4.35 ¢ per KWh for all KWh per month.

Adjustment for Contribution of Fixed Costs from Surplus & Interruptible Sales

DISCO currently offers large industrial customers the opportunity to purchase surplus or interruptible electricity at a price that covers the incremental costs but is not intended to make any contribution to fixed costs. On December 21, 2005 the Board ruled that:

- The price for surplus and interruptible energy should make some contribution to fixed costs;
- DISCO should submit a study of the issues and costs associated with extending such opportunities to other classes of customers, and
- DISCO should submit a study on the maximum amount of surplus and interruptible energy that should be available to each customer.

The Board heard evidence and argument relating to the appropriate magnitude of the contribution to fixed cost for surplus and interruptible energy sales. DISCO's witnesses were concerned that any contribution to fixed costs could prove detrimental to DISCO if it caused customers to switch from surplus and interruptible service to firm service. The PI's witness, Mr. Knecht, was less certain that a small contribution to capital would influence users to abandon the service in favour of firm service. His review of the evidence had revealed that the current charges for surplus and interruptible energy already included a small contribution of $1.40 per MWh and DISCO agreed. Mr. Knecht recommended that surplus and interruptible energy customers make a total contribution of $3 per MWh to fixed costs during 2006/07.

The Board affirms its ruling of December 21, 2005 and orders that DISCO's surplus and interruptible rates be modified to include an additional contribution to fixed costs of $1.60 per MWh. This total contribution is to be credited to the rate class to which the sales are made. DISCO is directed to:

1. Calculate the additional revenue that arises from this order and adjust the revenue requirements for relevant classes downwards from the values given in Table C,
2. Adjust the approved demand and energy prices accordingly, and
3. Submit the calculations and adjustments to the Board for review and approval.

Wholesale Class:

The revenue requirement approved by the Board for the wholesale class for 2006/07 represents an increase of 5.69% over existing rates. The Board lacks sufficient evidence to support differential changes to the energy and demand components of the wholesale rate and therefore approves the following rates, subject to the same adjustment as described above:

Demand Charge:	$11.75 per KW of the Billing Demand per month.
Energy Charge:	5.12 ¢ per KWh for all KWh per month.

Obligations of Surplus and Interruptible Customers:

The Board also heard that both DISCO and Mr. Knecht were concerned that surplus and interruptible customers might be inclined to move their load to firm service in anticipation of the refurbishment outage for the Point Lepreau generating station. This would be attractive to such customers because generation capacity constraints during the outage would normally be expected to lead to:

1. Substantial increases in the frequency and duration of service interruptions under that rate, and
2. Substantial increases in the marginal cost of energy as higher cost generation facilities are dispatched to replace capacity on outage.

The Board is concerned that DISCO's existing tariff provisions for surplus and interruptible energy may not provide sufficient protection for its firm service customers. The ability of surplus and interruptible customers to move to firm service in response to a short-term capacity constraint like the Point Lepreau outage and then resume surplus or interruptible service once refurbishment is complete, places the system benefits one might normally associate with such services in question. The Board therefore orders

DISCO to review the provisions of its tariff relating to surplus and interruptible service to ensure that they provide adequate and appropriate benefits and protection to firm service customers.

Water Heater Rental:

The revenue requirement for water heater rentals as approved by the Board for 2006/07 represents a decrease of 16.66% to the revenue that would be provided by the existing rates. The Board orders DISCO to reduce its water heater rental rates by 16.66%.

Unmetered Rates:

The revenue requirement for street lights and unmetered, as approved by the Board for 2006/07, represents a decrease of 10.05% to the revenue that would be provided by the existing rates. DISCO is ordered to reduce its rates for these services by 10.05%.

Connection Charges:

The Board approves the connection charges as proposed by DISCO.

Effective Date:

The changes in rates approved by the Board in this decision are effective as of August 1, 2006.

Cost Allocation Issues:

The Board, on December 21, 2005, issued a ruling with respect to the methodology to be used by DISCO in allocating its costs to the various customer classes. The ruling is attached to this decision as Appendix C.

The PI raised two issues with respect to the cost allocation methodology. DISCO allocated the costs for combustion turbines and emergency power purchases to the customer classes on the basis of the winter heat load. Mr. Knecht recommended that these costs be allocated on either a peak demand basis or an energy basis as all customers benefit.

The Board considers that these costs should be shared by all customer classes but will not require a change for 2006/07 as the amount of the cost is small. The Board directs DISCO to file a study at the time of the next general rate application that provides an analysis of whether peak demand or energy is the most appropriate method to use in allocating these costs.

The second matter raised by the PI was the treatment of the export sales credit. DISCO used this credit to reduce the costs allocated to the various customer classes. The PI believes that it would be more appropriate to use this credit to increase the revenues for each class because this would be consistent with the way that miscellaneous revenues are treated and because it would improve the revenue to cost ratios.

The total costs of DISCO, as approved by the Board, form the overall revenue requirement. The existence of the export sales credit reduces the amount of revenue that must be recovered from in-province customers. The amount of revenue to be provided by in-province customers remains the same whether the export sales credit is applied to revenue or to costs. If the amount of revenue to be recovered from in-province customers is allocated properly to the various customer classes then it should not matter which way the export sales credit is applied. Therefore, the Board will accept the way that DISCO has applied the export sales credit in the cost allocation study.

5. COMMENTS / RECOMMENDATIONS:

Hearing Costs:

Mr. Marois raised the issue of the cost of regulation and stated that he believed that a balance should be struck between the cost and benefits of regulation. He estimated the direct costs of the current proceeding to be well over $4 million and stated that there were additional indirect costs which he believed were of greater importance. Mr. Marois stated:

> *"there should be an objective of trying to make the regulatory regime as streamline and as efficient as possible to reduce both the direct and indirect costs to really leverage the benefits of it."*

Chairman Nicholson responded to Mr. Marois and stated as follows.

> *"Mr. Marois, I couldn't agree with you more. I can tell you however when the then minister responsible for NB Power introduced the legislation in the house back in 94/95, somewhere in that vicinity, he said as well that it has cost us $4,000,000 to appear before the Board. Therefore we are putting in this three percent cap so we don't incur that very great expense. Now I ask you, would it have been better every couple of years to spend $4,000,000 to appear before the Board or to lose $314,000,000 as occurred in that 13 year period?"*

Mr. Marois did not respond to the question. Chairman Nicholson continued and stated:

> *"…that over the three rate increase hearings we had in the early '90s, the time that it took to have those halved each time. So that the last general rate increase in 93/94 actually took I believe it was something like 12 days in hearings. I could be wrong but it's something like that.*

We all go through a learning curve. I'm saying it right now to you is that I sincerely hope when we conclude this hearing within two to three years you come back again so at least we can build upon what we have done here, and to your benefit and to the benefit of the customers of the Province of New Brunswick."(Transcript, p. 3924-5)

The Board is very concerned with the costs of the hearing, both in terms of the time requirements for all parties and the monetary expenditures. The hearing record includes 6377 pages of transcript covering 58 hearing days, 255 exhibits and over 900 interrogatories.

The Board has identified a number of factors that affected the cost and complexity of the hearing. These factors included 16 days to hold the pre-hearing conference, to hear motions and deal with confidentiality issues. Six days were required to hear evidence on the third party pole attachment rate that came before the Board when DISCO and Rogers were unable to reach agreement. The revenue associated with this matter is less than 0.3 percent of DISCO's total revenue requirement.

DISCO's original application, dated March 21, 2005, requested approval of a variable fuel surcharge, a fuel variance account to retroactively recover its fuel costs and approval of its charges, rates and tolls for 2005/06. When the Board rejected DISCO's application for approval of the variance account, it requested an adjournment and later filed an amendment to its application. The amendment requested approval of changes to DISCO's charges, rates and tolls for the 2006/07 year.

DISCO requested approval of an overall increase in its revenues of 11.4%. It had not been before the Board for a general rate application in 13 years. The application attracted a great deal of interest and evidence was filed on behalf of the applicant, 6 intervenors and Board staff. The application was heard in four phases which were:

1. Cost Allocation and Rate Design

2. One Year Load Forecast
3. Third Party Pole Attachment Rate
4. Revenue Requirement for 2006/07

The above noted factors all contributed to the complexity and cost of the hearing. The Board believes that if DISCO were to come before it with a rate application within 2 to 3 years that many topics examined in the current application could be dealt with in a more effective matter. Also, the Board was not satisfied with the quality of information provided by DISCO in support of its application and has ordered it to undertake a number of studies. The Board believes that more current and better quality information should help reduce the hearing length of a future application.

DISCO's financial record during the years when it did not appear before the Board speaks for itself. A privately held company would have either applied to the Board for sufficient increases to remain whole or been bankrupt. The Board's mandate is to balance the interests of the utility and ratepayers and to ensure that rates are fair and equitable. The Board believes that if DISCO adopts a policy to come before the Board on a regular basis filing updated and complete information, then the time expended and costs incurred because of regulation will diminish dramatically.

NB Power Operating Results 1994 to 2005:

Prior to the recent hearing, NB Power had not applied to this Board for an increase in its rates since 1992. That application was in connection with the setting of rates for the financial year ended March 31, 1994 and was the subject of a decision by the Board dated April 23, 1993. After that decision, a limitation was placed on the Board's supervisory powers. An amendment to the legislation permitted the utility to change its rates and tolls, without requiring Board approval, if the increase did not exceed the greater of three percent or the percentage change in the average New Brunswick Consumer Price Index. This limitation has been continued under section 99 of the Act.

Based upon evidence presented during the hearing, the Board concludes that such a limitation is unique in the regulatory field in North America. NB Power increased its rates and tolls during the period 1995 to 2005 without application to the Board by use of this limitation. During this time, the utility also changed a number of accounting policies; principally those related to regulatory reserve accounts approved by the Board in its decision dated May 22, 1991. Reserve accounts had been established to smooth out the impacts of variations in hydro and nuclear generation and in export sales. These reserves, referred to at the hearing as "rainy day accounts", had been accumulated over many years and were approved by this Board. They had a total balance in excess of $169 million. They were collapsed and the balances in the accounts were used to reduce losses in 1994/95, 1995/96 and 1996/97. NB Power eliminated the accounts without requesting approval from this Board.

The Board is of the opinion that timely applications by NB Power for increases in its rates and tolls would have prevented the utility from the decline in its financial position during the period in question. On March 31, 1993 NB Power had equity in the form of retained earnings amounting to $409 million. On March 31, 2005 the utility had a deficit of $192.0 million, representing a reduction of $601.0 million.

The Chairman discussed this matter with Ms. MacFarlane as follows:

> *"And the question was 'Provide the amount NB Power lost accumulatively from 1993 through 2004. And the response basically is there was a net loss of $595,000,000, including the $450 million write-off of the Point Lepreau Generating Station?'*

Ms. MacFarlane *"That's correct"*. (Transcript p. 3912)

In addition, Ms. MacFarlane stated that the elimination of the regulatory deferral accounts resulted in a reduction of reported operating losses of $169.0 million. The Board has accumulated the results reported by NB Power and the changes in the regulatory deferral accounts and these are shown in Appendix E.

Policy and Legislation Review

An important issue that arose throughout the hearing was the degree to which the outcomes of restructuring were in accord with the policy intentions of government and the purpose of the Act. The Board understands that the outcomes of restructuring are critically dependent upon the details related to its implementation and such details cannot and should not be included in the overall policy statements and enabling legislation. This makes it all the more important that the outcomes be evaluated against the policy goals and purposes of the Act.

The policy background to the Act is contained in the New Brunswick Energy Policy White Paper (White Paper), which was approved by Cabinet in December 2000. Facilitating a competitive market for electricity was the main impetus for restructuring, and the White Paper outlines the rationale for establishing a competitive wholesale market (White Paper, p.14):

1. Improved access to the New England market for electricity export sales, which were thought to have resulted in lower electricity prices for in-province consumers.[8]
2. Maintenance of the electricity price advantage that NB manufacturers and exporters have *vis-à-vis* their competitors in New England, which was supposed to be due to "... cost-based Crown utility rates being below Northeast market price";
3. Ensuring that "... major capital investments are subjected to a market test and ... allow[ing] the market to drive decisions regarding the need for additional electric generating facilities and strategies for reducing generation costs."

4. Holding "... investors, not customers, ...[responsible] ... for bad investment decisions."
5. Ensuring "... that New Brunswick's low electricity prices are maintained for the benefit of existing customers."

The Board has developed sufficient familiarity with the energy policy, the Act, and specific arrangements made in consequence thereof to make the following observations.

The State of the Electricity "Market"

The Board concludes that:

1. The required conditions laid out in the White Paper for a competitive market have not been met because:[9,10]
   a. The Crown utility's generation portfolio has not been broken up.

---

[9] "Economic theory and recent experience suggest that, at a minimum, approximately five equally sized firms are required to achieve a workably competitive market.[7] Moreover, the maximum market share of any one supplier generally should not be more than 35%.[8] Strictly speaking***, to achieve a workably competitive market within New Brunswick either the Crown utility's generation portfolio must be broken up or the province's transmission interconnections with adjacent markets must be significantly increased*** to allow for greater access to New Brunswick.[9]" ***[emphasis added]*** (White Paper, p.16).

[10] "... ***all of the five following conditions*** would ***need to be met if a competitive market is to be achieved within New Brunswick***:

(1) ***An RTO*** is established ***that encompasses New Brunswick, New York, New England, and Quebec*** and this RTO reduces the pancaking of transmission tariffs and minimizes wheeling through tariffs. (Transmission rate pancaking is the layering of additional transmission tariffs for each transmission system that is crossed from generation to end-use customer);

(2) ***Electricity generation and transmission are separated***, either corporately or through an RTO structure, and operated independently;

(3) ***A second 345 kV transmission tie line with New England*** is developed to increase New Brunswick's integration into the greater Northeast power market;

(4) The ***Crown utility's non-utility generation contracts and entitlements to the Courtenay Bay project*** are ***conveyed to a distribution company or*** the contracts are ***restructured so that these resources participate as competitive suppliers in the greater Northeast power market;***

(5) If all New Brunswick fossil and hydro generation units are owned by one party, then the ***hydro resources must not be price setting*** and there must be ***restrictions that prevent the owner of these hydro units from using them to physically withhold energy. In addition, the market would be more workably competitive, with less volatility, if the competition were limited to bilateral contracts and the Crown utility required to serve its distribution customer load through an entitlement contract." [emphasis added]*** (White Paper, p.16).

b. The province's transmission interconnections with adjacent markets have not been significantly increased, and no study has been made to support the notion that the proposed 2nd tie line to New England will be sufficient to permit a competitive market in New Brunswick.[11]

c. A Regional Transmission Organization (RTO) has not been established.

d. The NUG contracts have not been conveyed to a distribution company, nor have they been restructured to allow the resources to compete in the New Brunswick market.

e. The likelihood of the transmission and generation companies acting independently is put in question because of their common Board of Directors.

2. The structure of the PPA's confer "an inherent competitive advantage relative to new entrants"[12]to GENCO through the requirement that DISCO pay all of GENCO's fixed costs.

3. The current regulatory regime is not adequate to protect the interests of New Brunswick's electricity users in the absence of a competitive market.[13] Boards normally have the power to investigate customer complaints of regulated monopolies and impose remedies as required. This Board has just such authority in respect of both the natural gas distribution utility and the electric transmission utility it regulates. Similar authority was not granted in respect of DISCO, and the

[11] "There were no studies done to specifically determine whether the 400 MW is significant enough to form the foundation of a competitive market in New Brunswick. . . ." (Exhibit A-107)

[12] **"**An issue that could represent a barrier to entry in the wholesale power market is whether the Crown utility is perceived to have an inherent competitive advantage relative to new entrants. . . . **The Province will examine the issue of establishing a level playing field between the Crown utility and other market participants over the next two years and will ensure that this does not impede the development of a competitive wholesale market**." **[emphasis in original]** (White Paper, p.18)

[13] "To ensure that such savings flow through to their customers, the distribution electric utilities will be required to file their rates and any long-term power purchase agreements with the Board. In addition, the Province will empower the Board with the authority to initiate a distribution utility rate review upon the complaint of a customer or under its own initiative." (White Paper, p.28)

Board cannot initiate a rate review despite the clear policy intention that it should be able to do so.[14]

4. The mechanism used to handle stranded costs introduces an unnecessary barrier to market development.[15] The Act places the sole discretion for initiating a hearing into stranded costs in the hands of DISCO. The Board is unable to order such a hearing, and DISCO's customers are unable to initiate a hearing without giving notice of their intent to leave standard service. Customers cannot make a reasonable determination as to whether or not they should leave standard service until they know the stranded cost implications of their departure, and they cannot know those costs until the hearing is held. This is clearly a significant and unnecessary impediment to the development of the market.

In theory, the restructuring undertaken through the Act created a bilateral contract market, in which large industrial and wholesale customers can rely on contractual arrangements for the supply of electricity and GENCO is not required to build additional generating plant out of an obligation to serve. DISCO and the municipal distribution utilities remain obligated to serve loads within their service areas. Any additional

---

[14] The Board's power of investigation are strictly limited under section 128(1) of the Act, and relate only to matters where it appears to the Board:

"(a) that any person has failed to do any act, matter or thing required to be done under this Part or rule, order or direction made by the Board, or that any person has done or is doing any act, matter or thing contrary to or in contravention of this Part, or any rule, order or direction,

(b) that the circumstances may require it, in the public interest, to make any order or give any direction, leave or approval that by law it is authorized to make or give, or concerning any matter, act or thing that by this Part or rule, order or direction is prohibited or required to be done, or

(c) that there is an abuse or potential abuse of market power by a market participant."

[15] **"**Therefore, **the Province will impose a policy of user-pay with respect to recovery of stranded costs associated with the introduction of wholesale competition, nonutility generation and retail competition wherever feasible and in a way that does not unnecessarily impede the development of a vibrant wholesale and retail market." [Emphasis in original]** (White Paper, p.29)

electricity required by such distribution load growth is to be purchased in a competitive bilateral contract market.

In fact, GENCO is an unregulated monopoly supplier of electricity**.** The monopoly was made virtually complete when the NUG contracts were assigned to GENCO rather than DISCO. Further, as noted below, GENCO's fixed asset costs are fully assigned to and paid for by DISCO under the vesting PPA, but GENCO retains the rights to much of the energy from those assets. GENCO can bid that energy into any developing market at a price well below that of competitors, who must recover their fixed costs in the supply contracts. Whatever the merits of these arrangements, they constitute a cost-advantage for GENCO that flies in the face of the government's intention to "level the playing field" between GENCO and new entrants to the market.

Application of the Principle of a Level Playing Field

The Board finds no basis in law or policy to justify its consideration of the notion of a "level playing field" between different energy sources in setting electricity rates.

During the hearing, some participants referred to the provincial government's intent to establish a "level playing field" between companies that supply different types of energy sources that may be used for the same purpose. For example, space heating and domestic hot water heating needs can be met using electricity or fuel oil throughout most of New Brunswick, and some residents can use natural gas for the same purposes. It was suggested that a "level playing field" between suppliers of these commodities was a goal of the provinces energy policy.

The Board notes that the white paper contains specific sections relating to markets for natural gas (3.2.2.2. Development of a Competitive Retail Market, p. 34; 3.2.4. Market-Based Fuel Selection, p.36) and fuel oil (3.3.2.2. Heating Oil, p.42). None of these sections identify a "level playing field" with electricity as relevant consideration, even though they deal with issues to which electricity pricing is particularly relevant.

In sub-section “3.1.3.4. Levelling the Playing Field”, the white paper makes it clear that government was particularly concerned that the incumbent Crown utility should compete fairly with new entrants to the wholesale electricity market (White Paper, p.18):

> **“**An issue that could represent a barrier to entry in the wholesale power market is whether the Crown utility is perceived to have an inherent competitive advantage relative to new entrants. . . . **The Province will examine the issue of establishing a level playing field between the Crown utility and other market participants over the next two years and will ensure that this does not impede the development of a competitive wholesale market**.” **[emphasis in original]**

The only reference the White Paper makes to a “level playing field” is in this section and in a subsequent summation that refers to this section. The concern is with the inherent advantages that GENCO has *vis-à-vis* “for-profit” market generators. These include its “exempt[ion] from federal and provincial corporate income and capital taxes, excused from some property and all water use taxes, and has its debt guaranteed by the Province.” A footnote indicates that this represents a 10% to 20% cost advantage. This concern was dealt with in section 37 of the Act, which requires DISCO and its affiliates to make payments in lieu of income taxes (PILTs) that they would have paid had they been private corporations.

Power Purchase Agreements and Non-Utility Generation Contracts

Introduction

A portion of the hearing dealt with the nature of the power purchase agreements (PPAs) that govern the supply and cost of electricity in New Brunswick. There are two basic types of such agreements:

1. Those between DISCO and its affiliated NB Power companies (GENCO, COLESONCO, and NUCLEARCO); and
2. Those between GENCO and various non-utility generators (NUGs) within New Brunswick.

The PPAs between DISCO and its affiliates represent the largest portion of DISCO's costs for the test year, over 1 billion dollars. The Board would normally have examined the assumptions, practices and decisions that lay behind such costs to determine if they were prudently incurred and reasonable. Because these transactions are between regulated and unregulated affiliate companies, they create an opportunity to burden the regulated company's ratepayers with costs they should not bear. The Board was specifically barred from making such an examination by section 156 of the Act.

A thorough examination of the nature and disposition of the power purchase and supply arrangements between DISCO, its affiliates, and the non-utility generators (NUGs) was not made in the course of the hearing. The evidence that was heard identified certain areas of concern that the Board intends to address at the time of the next hearing, when section 156 no longer applies.

There are three power purchase agreements between DISCO and its affiliates. They are:

1. The COLESONCO Tolling Agreement.
2. The NUCLEARCO Energy Purchase Agreement.
3. The GENCO Vesting Agreement.

Together, these three agreements are responsible for 1.028 billion dollars (approx. 80%) of DISCO's costs.

While these agreements define DISCO's costs, there is no mechanism in place to ensure that they fairly reflect the actual costs of these affiliates. This would not pose a problem if these companies were subjected to and reasonably influenced by competitive market forces, as the White Paper clearly anticipated. In that case, DISCO and other market participants would be able to "shop" for the best service and price from many (or at least several) potential suppliers, and such competition might be reasonably expected to result in fair costs for DISCO.

Absent competition, it is reasonable that the costs of DISCO's suppliers be subject to review and regulation by this Board. This was the position of most intervenors in the hearing and the evidence of the PI's experts.

Unfortunately for New Brunswick's ratepayers, the Board has no authority to regulate GENCO or order the production of relevant cost information by GENCO in the context of a rate hearing. This lack of authority to compel the production of evidence was central to a significant issue in this hearing.

NUG Contracts

The NUG contracts are contracts for the supply of power and energy from non-utility generators in New Brunswick. As noted above, the White Paper anticipated that these contracts would be assigned to a distribution company upon restructuring. Indeed, it was one of the five conditions that were identified as necessary for development of a market.

The Board understands that these contracts contain confidentiality clauses of customary and reasonable kind. These clauses typically require the parties to hold the contract in confidence unless a competent authority orders disclosure. Had the NUG contracts been assigned to DISCO, the Board could have ordered they be filed on a confidential basis to confirm (or refute) the reasonableness of the fuel cost estimates for natural gas, a significant contributor to DISCO's total costs for the test year.

Because the contracts were assigned to GENCO, the Board could not order their production, and DISCO could only request that GENCO provide them for this hearing. The Board understands that this request was made by DISCO, that GENCO sought the permission of the non-utility generator to file them on a confidential basis, and that this permission was not granted.

This matter is relevant to the rate application because all of the energy and power arising from the NUG contracts are conveyed to DISCO under the vesting PPA. The vesting PPA requires that fuel consumption for the NUG plants be estimated using the modeling assumption that all of the NUG plants are dispatched on a must-run basis, irrespective of their economic merit order[16], or whether they represent hydroelectric, co-generation, or merchant generator assets.[17]

If a particular NUG plant was modeled as "must-run" but was in fact dispatched in merit order, the fuel volume and cost estimates used to support the rate application would be too high, and the Board would reduce the revenue requirement for the test year. On the other hand, if all of the NUG plants are contractually committed as "must-run" units, the Board would be interested in the magnitude and allocation of cost associated with those commitments and the reasonableness of such arrangements.

The Board sought the NUG contracts to confirm that the contract language supported the modeling assumption. Witness testimony during examination indicated that DISCO was concerned that dispatch in merit order would result in financial harm to the NUGs. This stands in contrast to evidence filed by DISCO that clearly separated the capacity cost (29.8 M$) and fuel cost (95.3M$) for the natural gas fired plants (Exhibit A-95, p.12).

---

[16] In the normal course of events, generation units with the lowest variable costs are dispatched first, followed by a succession of plants with incrementally higher fuel costs, until the full demand is met. This leads to the lowest overall cost of energy, and leaves plants that burn a high cost fuel like natural gas or light fuel oil off of the grid (shut down) in all but the coldest weather, which coincides with the time of highest demand. ***Designating a plant as "must-run"*** means it operates irrespective of the fact that a cheaper source of energy is available, and ***results in electricity costs that are higher than otherwise achievable.***

[17] The distinction between co-generator and merchant generator assets may be important in this context. A co-generation or combined heat and power plant is designed to provide both electricity and heat and can provide environmental benefits while doing so. A merchant generator normally provides only electricity. A must-run designation ***may*** be a legitimate condition of a supply contract with a co-generator, for whom dispatch might interrupt their manufacturing process and cause them to incur extra costs. Where a co-generator demands such a contract clause one would reasonably expect a commensurate reduction in the overall cost of energy *vis-à-vis* a merchant generator, for whom separate capacity and energy payments are normally sufficient.

The separately quantified capacity and fuel costs of Exhibit A-95 suggest that the underlying contracts provide for separate fuel and capacity payments. Such separate payments could and should preserve the financial interests of the NUGs, by providing for their investment costs (including profit) in the capacity payment, and using the fuel payment to cover the variable costs that arise only upon dispatch of the plant.

DISCO filed confidential evidence indicating that fuel costs would be substantially lower if the natural gas units were dispatched in economic merit order. The net benefit to DISCO in this circumstance would be savings of a substantial sum of money.

Export Sales

The Board notes that a consequence of designating the NUG capacity as “must run” for in-province load, and thus assigning higher costs to New Brunswick customers, is that the lower cost capacity displaced by the NUG resources is available to compete in the export market. Because it can be priced lower than the NUG capacity in the export market, it is reasonable that a greater export sales volume (MWH) results. It is also possible that larger export revenues will be earned, depending on market conditions and transmission constraints.

Proceeds from export sales are “shared” between DISCO and GENCO as outlined in the vesting PPA. DISCO’s annual share is fixed as the Third Party Gross Margin Credit on a 5-year forward-looking basis, and GENCO is “at risk” for annual variations within ±20% of the set amount. That is, DISCO receives the set amount as long as the actual proceeds are within 20 percent of that amount. If net export revenues fall more than 20% below the set value, DISCO’s “share” is reduced; if net revenues exceed expectations by more than 20%, DISCO receives one-half of the amount in excess of 120% of the set value.

It is important to note that the vesting agreement requires DISCO to pay the fixed costs associated with GENCO’s assets. This means that the long-term financial risks associated with owning the generation assets is borne by DISCO and its customers. In the short to medium term, some of this risk is transferred back to GENCO by the mechanism of the Third Party Gross Margin Credit. On balance, DISCO's customers carry more of the long-term risk associated with generation than the owner/investor. This stands in stark contrast to the policy intent of the White Paper, which proposed that ". . . investors, not customers, . . .[should be responsible] . . . for bad investment decisions."

Further, since DISCO assumes this risk, normally the most significant risk borne by a generator, it is reasonable to expect that DISCO would obtain a much larger share of the export benefits than GENCO. On their face, the provisions of the PPAs relating to sharing of export benefits between DISCO and GENCO seem tilted in favour of GENCO.

Insurance

The PPA's require that GENCO, NUCLEARCO and COLESONCO (Generators) carry insurance to cover the replacement cost of their Facilities, the cost of premiums for which DISCO must ultimately pay as an expense passed through the PPA's. The PPA's do not appear to require that Generators cover any shortfall in the case that proceeds from insurance claim(s) are insufficient to make all necessary repairs. It thus appears that DISCO's customers' bear risks that the White Paper anticipated would flow to the generation plants' investors. If the Generators do not ensure that there is sufficient insurance and that the cost of rebuilding is reasonable, DISCO's customers bear the entire financial burden of any shortfall.

Costs Associated with Environmental Upgrades

Costs associated with environmental upgrades are capped at a Firm Estimate of costs. If actual costs come in below the Firm Estimate, the savings are shared equally between DISCO and the generator. One can view this as an incentive to the generator to manage the project to minimize costs.

Unfortunately, this arrangement also creates an incentive for the Generator to overestimate the cost of the upgrade when it makes the Firm Estimate. If it can set the Firm Estimate higher than the likely cost of the upgrade, DISCO assumes the risk of cost overruns up to the Firm Estimate. If the project goes well and comes in below the Firm Estimate, the Generator gets to keep half of the "savings". If the project goes poorly, the high Firm Estimate protects the Generator at the expense of DISCO's customers.

The main safeguard that would normally protect against such abuse is the independence of DISCO and GENCO. An independent DISCO could be expected to make all reasonable efforts to ensure that the Firm Estimate was in fact a fair estimate of project costs. Unfortunately, testimony in this hearing made it explicitly clear that the senior management of DISCO is willing to sacrifice DISCO's interests to the larger corporate interests of its affiliated companies[18] The Board is concerned that similar accommodations would be made to GENCO in respect of Firm Estimates, to the detriment of ratepayers.

Coleson Cove Corporation Tolling Agreement

Heat Rate Adjustment[19]

Schedule 2.9.4 provides for a monthly adjustment to the price paid for electricity from the plant's generators. This adjustment is numerically equal to the difference between the Targeted Fuel Use and Actual Fuel Use, multiplied by the Heavy fuel Oil Cost.

---

[18] Question:

> "So as Vice-president in charge of DISCO you didn't put up any opposition [to the change in hydro flow adjustments]? Or you didn't look at your customers in the sense of the benefit that it could be to your customers? You didn't -- you didn't oppose this at all?"

Answer:

> "Well, like I said, if I would not have been satisfied that the change in methodology was the right thing to do, I would definitely have opposed it. But I'm not going to oppose something just because it's going to result in a higher cost to me. My criteria is common sense and is it the right thing to do." (Transcript, p.4507).

[19] "Heat rate" is the term used to define the amount of fuel a generating plant must burn to produce a unit of electricity. The customary units are *Btu per KWh.* The heat rate is multiplied by the price of fuel (in *$ per Btu*) to determine the fuel cost for a particular plant.

The Targeted Fuel Use is the product of the actual net electricity output of the generator and a Target Heat Rate, which can vary from month-to-month depending on the load placed on the generator. The Heavy Fuel Oil Cost is defined to be the price for heavy fuel oil in New York harbour, in US$ per barrel, plus 1.00 US$[20]. This sum is divided by 6.3 to convert from US$ per barrel to US$ per million Btu.[21] The New York harbour price is based on the values reported in "Platt's Oilgram U.S. Marketscan." If this index is no longer published, the Operating Committee is directed to determine an appropriate replacement and (*Sch 2.9.4 – Page i*) ". . . whether any additional adjustments are required to the definition of Heavy Fuel Oil Cost, including amounts reflecting transportation costs . . ."

The net effect of the heat rate adjustment is to reward the generator for exceeding the target heat rate and penalize it for failing to achieve the target. The Board considers this reasonable in its principle, but is concerned that its overall reasonableness depends upon the specific facts of the matter. In this regard, the Board is concerned that:

1. The price adjustment mechanism does not appear to reflect DISCO's actual cost for residual fuel oil, which is purchased at least one year in advance;
2. Evidence supporting the $1.00 per barrel surcharge should be examined to determine its reasonableness;
3. The Target Heat Rate sets the standard against which performance is judged, and COLESONCO's and DISCO's interests in it are contradictory, making it critically important that they act as independent entities when negotiating its value;
4. The Operating Committee appears to have considerable discretion to adjust the source of the Heavy Fuel Oil Cost once the Platt's report is no longer published, and (perhaps unintentionally) no discretion to adjust it absent that event; and

[20] The additional *1.00 US$* presumably reflects incremental transportation cost over and above delivery to New York harbour.

[21] This is consistent with the value of *6.287 million Btu per barrel* used by the US Energy Information Administration for residual fuel oil.

5. DISCO has the right to require, observe and obtain the results of heat rate tests of the generation units, but had not done so since the major refurbishment.

Unit Performance

Section 2.6 provides a pro-rated reduction in the capacity payment in any winter period (January, February and March) where the availability[22] of the unit generators falls below 95%, and any summer period (June, July and August) where the availability of the unit generators falls below 85%. Such adjustments are reversed if the three-month average availability of a unit exceeds the target.

The Board is concerned that the "compensation" to DISCO for an availability shortfall during a peak winter month, being a reduction in its capacity payment, can be reduced or eliminated by "excess" availability during non-peak months. The market price of electricity varies substantially in the winter months, as illustrated in Table 1.

Table 1
New England Market Price of Electricity at Keswick, New Brunswick for the Winter Months of 2004/05 and 2005/06

Month	Average Monthly Price - US$ per MWh	
	2004/05	2005/06
November	$45.14	$64.88
December	$51.98	$91.50
January	$61.30	$63.37
February	$49.42	$60.80
March	$56.35	$59.16

[22] A generator is ***available*** if the system operator ***can*** dispatch it to meet load, irrespective of whether or not it is dispatched. ***Availability*** is defined under the tolling agreement as the ratio of the energy that would have been generated if it had been dispatched at it's ***declared*** capacity in each hour of a month, divided by the energy that would have been generated if it had been dispatched at its ***contracted*** capacity.

This wide variation in winter energy prices, and the fact that higher prices are historically associated with periods of very cold weather, makes unit availability in peak months much more valuable to DISCO than it is in non-peak months. The performance clause does not appear to adequately reflect this reality.

GENCO Vesting Agreement

Energy Entitlement and Excess Entitlement

Under the vesting agreement DISCO is required to pay for all of GENCO's fixed costs through a capacity payment. It can only reduce its payments by reducing it's Nominated Capacity. The Nominated Capacity is initially set at 2425.1 *MW*, which represents all of the base load capacity owned or under contract to GENCO and/or COLESONCO.[23] A total of *1258.4 MW* of peaking capacity is also assigned to DISCO, and this amount varies *pro rata* to the Nominated Capacity. DISCO cannot adjust the amount of peaking capacity it buys from GENCO independent of the amount of base-load capacity that it buys.

DISCO's energy entitlement (Section 3.1.2) is limited to *56.5%* of that which would be produced if the base-load assets ran fully loaded for each hour of the year. This is substantially less than the *85%* production capacity that is normally expected from well-managed base-load generation assets. The difference between the reasonably expected production capacity and DISCO's entitlement is equivalent to some *690 MW* of production capacity that DISCO pays for but GENCO is free to sell on the open market.

The variable cost to GENCO for this excess energy is simply the marginal cost of fuel and maintenance. The fixed cost to GENCO for this energy is the Third Party Gross Margin Credit it pays to DISCO. This is scheduled to be *$69.4* million during the test

[23] This figure does not include the capacity attributable to the Point Lepreau Nuclear Generating Station, which is covered by a separate PPA. It also excludes Courtenay Bay Unit 4, a 97.7 MW residual fuel oil fired steam turbine. This unit is credited to peaking capacity.

year, which is equivalent to *$8377 per MW-month.*[24] The Board notes that Schedule 1.1.17, Page ii of the vesting agreement indicates that DISCO pays GENCO *$9166.67 per MW-month* for Nominated Capacity during the test year. Under the existing arrangements, therefore, DISCO is required to sell capacity to GENCO at a price lower than GENCO charges DISCO for the same capacity. The Board would normally expect that such transactions would be effected at the same price. Because they are not, DISCO's customers appear to subsidize GENCO by $6.5 million for the test year.

The price paid by DISCO to GENCO is scheduled to rise from *$9166.67 per MW-month* to *$10,416.67 per MW-month* in fiscal year ending March 31, 2008, an increase of 13.6%**,** and stay constant for the following 8 years. The price paid by GENCO to DISCO (the Third Party Gross Margin Credit) is scheduled to rise by *0.3%* for fiscal year ending March 31, 2008. It then falls by 72% in the following year[25], presumably a consequence of the Pt. Lepreau station's refurbishment outage, and:

> *"In October, 2008, DISCO and GENCO shall establish the Third Party Gross Margin Credit for each of the 5 fiscal years in the period commencing April 1, 2009 . . . "*

As noted above, the Board is concerned that these terms and conditions may not adequately reflect the government's policy intent as indicated by the White Paper and the legislation. They burden DISCO with risks that a plain reading of the White Paper would suggest should be borne by GENCO. They also appear to subsidize GENCO's participation in the developing market. This tilts the "playing field" strongly in favour of GENCO *vis-à-vis* other potential market participants, in complete contradiction to government policy.

---

[24] *$69.4* million divided by 12 months is *$5.78* million per month. Dividing *$5.78* million per month by *690 MW* yields the price paid by GENCO for the capacity: *$8377 per MW-month*.

[25] FISCAL YEAR 2007/08, $69.6 million; FISCAL YEAR 2008/09, $19.4 million. (Sch. 6.3, Vesting PPA)

The Board also notes that the payments by DISCO to GENCO are adjusted upwards annually to compensate for general inflation, but no such adjustment is made to the payments from GENCO to DISCO. Such asymmetrical treatment is not appropriate.

Load Factor Improvement

A well-managed capital-intensive company would normally be expected to seek load factor improvement to improve asset utilization rates. It would do so by taking steps to reduce peak demand, or the rate at which peak demand grows, while maintaining or increasing sales volume. The energy entitlement provisions of the vesting agreement frustrate such good management practice.

For example, if DISCO were to reduce its peak demand while holding its energy sales constant by load shifting through time-of-use rates[26], it would be reasonable for it and its customers to capture the benefit of that demand reduction by reducing its capacity nomination under the PPA. Unfortunately, DISCO's energy entitlement is proportionate to its capacity nomination. Reducing its nomination would thus reduce its energy entitlement, forcing it to enter "the market" to purchase the difference between their constant energy requirement and their entitlement under the new nomination. As noted above, GENCO clearly dominates "the market", and the net result would likely be that DISCO would pay the New England price to GENCO for the energy shortfall. It is generally anticipated that this price would be higher than the embedded cost of energy under the PPAs, reducing the incentive for load factor improvement by DISCO and its customers, and thereby transferring the benefits of such improvement to GENCO.

Such a disincentive for good asset utilization is not in the best long-term interests of either DISCO's customers or the shareholder. It is also inconsistent with the direction established in the government's White Paper.

---

[26] It should be noted in this context that the White Paper states:

> "electricity time-of-use rates will be introduced to inform customers about the true cost for consumption and provide them with price signals for making economically based decisions about energy efficiency and controlling their energy costs;" (White Paper,p.vi).

Third Party Purchases Benefit Adjustment

This portion of the agreement provides for GENCO and DISCO to share equally in any savings achieved by supplying DISCO with electricity from third parties that is priced lower than the vesting agreement price. It is not clear how development of a robust market is served by having the dominant supplier (GENCO) act as an agent or broker for DISCO in acquiring energy from other market participants. Rather, it seems likely that potential competitors to GENCO would prefer to sell directly to DISCO. On its face, it would also seem preferable, at least for DISCO's customers, to "cut out the middleman" and purchase directly from the cheaper supplier.

The vesting agreement does not appear to facilitate this option. Rather, it appears to frustrate the development of a competitive market by promoting the incumbent and dominant Generator's active involvement as an agent of the largest load-serving entity in the market. At the same time it appears likely to result in electricity prices that are higher than necessary for New Brunswick customers. It does appear to provide some protection from competitive market forces for GENCO, which may be of limited benefit to the shareholder.

Point Lepreau PPA Shortfall

The Point Lepreau PPA specifies that it is to provide 4,240 GWh per year before refurbishment and 4,500 GWh after refurbishment. In the event that production falls short of the target, GENCO is obligated to make up the difference between the target and actual production. In exchange, DISCO is required to pay GENCO a premium for that make-up energy such that the total price paid for it equals the price that would have been paid to NUCLEARCO if it had met the target. This is problematic from two perspectives.

The first and most obvious problem with the arrangement is that it holds the generation side of NB Power harmless in its failure to meet production targets. Failure to meet production targets at the Point Lepreau plant could arise from bad luck or bad management. In either case, NUCLEARCO's revenue will be reduced by an amount proportionate to the shortfall, and GENCO's revenue will be increased by the same amount, leaving the combined companies unaffected. While GENCO and NUCLEARCO are separate "persons" at law, they are also closely affiliated corporations with the same Board of Directors, the same President, and the same owner/investor. Together, they suffer no penalty for a production shortfall that could be reasonably expected to arise from bad management. The Board finds this difficult to reconcile with the government's policy intentions, and with its own appreciation of good business and regulatory practice.

The second and (perhaps) less obvious problem with the arrangement arises from the different price bases of the NUCLEARCO and GENCO PPAs. The NUCLEARCO PPA was structured so that DISCO pays it a simple price, in $ per MWh, for energy delivered. This price clearly includes compensation for both fixed costs and variable costs. The GENCO PPA is structured with separate capacity and energy payments, and the capacity payment is designed to recover all of GENCO's fixed costs. In the event of a shortfall by NUCLEARCO, GENCO will make it up using capacity that is already fully paid for by DISCO, and charge a price that includes an allowance for capacity, effectively double billing DISCO for capacity.

The rationale for this is apparently the notion that, by virtue of its obligation to provide make-up energy, GENCO foregoes the opportunity to sell that energy in the market, and the NUCLEARCO energy price was thought to be a reasonable proxy for the market price. The implicit assumption in this notion is that that GENCO would actually be able to sell all of the make-up energy in the market at the time that the shortfall was being supplied.

To test this assumption, the Board notes that GENCO reported export sales of 305 GWH on all paths for July and August, 2005. Deliveries on the only direct connection to the large New England market, the MEPCo tie line, were 266 GWH, 26% of that line's nominal capacity for the period. New England faced its peak load for 2005 in the hour ending 3:00 pm EDT on July 27. In that hour, the MEPCo tie-line carried 238 MW. It is normally capable of 700 MW. These facts suggest that transmission issues did not significantly restrict GENCO from selling excess energy into the New England market during those months.

The Board also notes that, had NUCLEARCO been unable to deliver energy during the 2 summer months of 2005, GENCO would have been called upon to provide some 937 GWH of energy to DISCO to make up for the shortfall. In that case, GENCO would have had to forego no more than 305 GWH of export sales, the amount it was actually able to export, and not the 937 GWH implicit in the PPA.

On this basis, the pricing provisions of the Point Lepreau PPA shortfall clause appear to be inconsistent with public policy goals and raise a reasonable apprehension of unfair treatment for DISCO's customers.

Capacity Payment

The monthly payment for capacity is given in Schedule 1.1.17. It shows that DISCO was scheduled to pay $8,333.33 per MW-month in fiscal year 2004/05. This increased by $416.67 for fiscal year 2005/06 and a further $416.67 for the test year, fiscal year 2006/07. It is scheduled to rise by a further $1250 for fiscal year 2007/08, for a total rise of 25% over 3 years. It is then to remain relatively constant until fiscal year 2017, whereupon it is reduced by approximately 1 per cent per year until 2030. The Board heard that the rationale for the variation in capacity payments was to allow for the required return to GENCO over the life of the agreements. The basis for the calculation of the capacity payment is not shown and therefore cannot be assessed for reasonableness. As well, the formula for CPI adjustment is not straight forward, and thus is difficult to rationalize.

Legal and Legislative Issues:

Introduction:

DISCO's application for approval of revenue and rates for the test year 2006/07 is the first such hearing conducted by the Board pursuant to the Act. The Act was proclaimed effective October 1, 2004 save for sections 5 and 80, subsections 99(2) and 99(3), sections 156 and 157 and paragraph 175(1)(b). Of those provisions section 156 has a major and material impact on this decision. The Application was made pursuant to Part IV of the Act.

Section 156 appears in Part V of the Act under the heading "Transitional" and was proclaimed effective May 9, 2005. Section 80 appears in Part IV of the Act and was proclaimed effective October 13, 2005. Section 156 states that for the purpose of the first hearing before the Board under Part IV of the Act that all assets transferred to the various subsidiaries of HOLDCO, including DISCO, before the commencement of the section, are deemed to have been prudently acquired and useful for the purposes of DISCO. As well, section 156 provided that any expenditures arising from various service contracts entered into, *inter alia*, by DISCO before the commencement of the section are deemed to be necessary for the provision of the service.

Such are normally matters for the Board's consideration and decision in a typical revenue and rate application. The delay in proclamation of section 156 allowed DISCO to conclude negotiations related to several service contracts with affiliated companies and have them protected from scrutiny. Had section 156 been proclaimed along with the other portions of the Act, these service contracts would have been open to scrutiny by the Board during this hearing.

Prior to closing submissions the Board requested that DISCO and the intervenors address in their final submissions several issues that the Board considered it should have input on, before the hearing concluded. In addition, the PI in his final submission raised a legal issue for the first time.

Section 156:

In respect of section 156 the Board requested input on the section's impact on any applications to the Board following delivery of the present decision. The Municipals made a substantial argument that this section is spent and has no further force and effect upon the conclusion of the present hearing. The PI and CME concurred in that position. EGNB, while saying it had no comment on the effect of section 156 on subsequent hearings, did caution that such a determination should be left to the next hearing as it is only then that it becomes a material issue. DISCO agreed that this section is spent upon completion of the present hearing but submitted that it has residual legal impact on subsequent hearings. Essentially DISCO argued that for all subsequent hearings the asset values and expenditures deemed necessary and prudent by section 156 are binding on the Board. That is, the Board cannot revert to its normal prudency reviews in such subsequent hearings because the legislature, through the medium of deeming provisions of section 156, has precluded all such future reviews save as there is a material change in any of the assets or contracts.

The Board agrees with the analysis provided by the Municipalities and finds that section 156 is spent and of no force and effect in respect of any applications following delivery of the present decision. The Board does not accept the submission by DISCO that section 156 has a residual impact arising out of its deeming provisions. Its position does not give proper consideration to the opening words of the section which clearly state that the section applies *"for the purposes of the first hearing before the Board …"*. Those words apply to the whole of the provision and there is no wording in the section, which suggests, or by necessary implication suggests, that its provisions are to have any impact on subsequent hearings. The Board notes that section 156 appears in Part V of the Act under the heading "Transitional Provisions". In keeping with the modern day rules of statutory interpretation that require a statutory provision to be examined in the context of the whole of the enactment the Board finds the appearance of section 156 in that portion of the Act supportive of its conclusion.

Exit Fees:

A number of participants raised the issue of the fees payable upon a municipal distribution utility or an industrial customer leaving standard service. Such fees are generally referred to as "exit fees" and are addressed in sections 78 and 79 of the Act. The Board's concern is that the development of the electricity market as envisaged by the Act will be inhibited should such customers have to give notice of leaving standard service to DISCO prior to being able to determine definitively what exit fee it would have to pay. The exit fee is payable upon such customer leaving standard service or by reducing its standard service commitment through third party purchases of energy or by self supplying a portion of its energy requirements.

The Board requested DISCO and the Intervenors to address this issue in their final submissions. Essentially there are two interpretations that can be placed on sections 78 and 79. First, that they must be read conjunctively in that they must be read together in such a way that formal notice of leaving standard service is required before an appearance before the Board can be invoked to have the Board determine the exit fee. Second, that the formal notice required by section 78 establishes one procedure that is separate from and independent of the provisions of section 79. Section 79 can be invoked to have the Board determine the exit fee without having to give the notice called for in section 78, That is, the sections are to be interpreted disjunctively.

The NBSO, while not an active participant in the hearing, considered the issue to be very important to the development of the energy market. Upon receiving information that the Board wished the issue addressed in the hearing it applied to the Board for leave to make a submission on the issue and received approval therefor, with the concurrence of the participants.

The Municipals submitted that both interpretations could be placed on the sections. EGNB and DISCO were of the view that the two provisions could be read disjunctively. That is, it is clear from the overall intent of the Act that the notice required by section 78 is not a condition precedent to a customer invoking the provisions of section 79. Section 79 allows the Board to determine a exit fee so the customer could obtain essential information in respect of its cost of leaving or reducing standard service before making a decision to do so or not.

The NBSO agreed with EGNB and DISCO that the sections can be read disjunctively but says that DISCO is in error when it suggests there are only two interpretations that can be placed on the sections.

Various participants suggested, in light of the ambiguity in the interpretation of the sections, that the Board should examine the provisions in the context of the whole of the Act which has as one of its primary purposes the development of a wholesale market for energy. It was suggested that the Board exercise its powers provided in section 128 and 130 of the Act to rule in favour of the disjunctive interpretation of the sections.

The Board notes that section 128 appears in Part V of the Act and the section is limited in its application to matters arising under that Part of the Act whereas the present application was made pursuant to Part IV. As well, the Board is mindful of the cautions imposed on the use of the general "public interest" authority provided it in section 130 as expressed in a recent decision of the Supreme Court of Canada: *ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utility Board)*, 2006 SCC 4, handed down in February 2006.

The Board does not agree with the interpretation placed on sections 78 and 79 by the NBSO and concurred in by the PI, the Municipals and EGNB or the position of DISCO Applicant. The Board's interpretation is that upon a plain reading of the two provisions that formal notice must be given by a customer pursuant to section 78 of the Act that it will leave standard service before that customer can invoke the provisions of section 79 to have the Board determine the exit fee. The Board is not prepared to invoke sections

128 and 130 of the Act in respect of its interpretation of sections 78 and 79 as it does not consider them to have application to the matter of exit fees. The Board therefore cannot initiate a hearing into exit fees.

Sections 98 and 99:

The PI in his final submission suggested that the provisions of section 98 and subsection 99(1) are capable of being interpreted as allowing a rate increase by DISCO in any given fiscal year of more than 3% without a hearing before the Board. He requested the Board address the issue in its decision. Specifically his submission was that DISCO could raise its rates by 3% pursuant to section 98(1) notwithstanding the limitation found in subsection 99(1) in a fiscal year in which DISCO receives a rate increase approved by the Board.

The Municipals and DISCO both argued that on a plain reading of Part IV of the Act pursuant to which the application was made that any increase in rates in a fiscal year which would bring the cumulative total of rate increases in that fiscal year above 3% would require application to and approval of the Board before being instituted. The Board agrees with the submissions of the Municipals and DISCO and rules accordingly.

Hydro Adjustments:

There was considerable discussion at the hearing relating to the possible impact of above average hydroelectric generation in 2005/06. GENCO owns several hydroelectric generators that supply energy to DISCO. For the purposes of the PPAs, the annual production of energy from these generators is assumed to be 2654 GWh. The 2654 GWh is based on the average annual amount of energy produced by the hydroelectric generators over a significant period of time. Whenever the annual production is below this amount DISCO makes a payment to GENCO and if the production is higher then GENCO makes a payment to DISCO.

Section 6.12 of the Vesting Agreement between DISCO and GENCO governs these adjustments. The 2654 GWh is specified and is used to calculate the variance in the amount of production for a given year. However, the price per GWh to be used is not specified. The section refers to the incremental costs incurred or avoided by GENCO but does not specify how these incremental costs are to be determined. NBSO normally dispatches generating facilities on the basis of least cost. The least expensive units are dispatched first and, as demand increases, more expensive units are brought online. The incremental cost, at any particular point in time, is the cost of producing one more unit of electricity.

DISCO and GENCO have each appointed a representative to an operating committee ("Operating Committee"). That representative is authorized to act on their behalf in addressing operating and administrative issues related to the Vesting Agreement between DISCO and GENCO.

Initially, the Operating Committee decided to use the incremental cost at the top of all energy produced, including export sales, for setting the price to be used in Section 6.12. This meant that GENCO's most expensive source of electricity was used to establish the incremental cost. On August 30, 2005 the Operating Committee decided that it was more appropriate to use the incremental cost at the top of the in-province energy production as the price for Section 6.12 adjustments. This change in methodology was made retroactive to April 1, 2005. The amount of energy required in-province is less than the amount necessary to serve both the in-province and export markets. As discussed above, the greater the amount of energy produced, the higher the incremental cost. The change in the methodology used to establish the price for Section 6.12 therefore has the effect of reducing the cost associated with the payments that must be made by DISCO or GENCO. This is because the quantity remains the same but the price is lower.

Actual production by GENCO's hydro-electric facilities during the first eight months of the 2005/06 year was 655.6 GWh higher than average, as water flows were significantly greater than average. This extra production, in only eight months, was approximately

25% more than the normal full year production of 2654 GWh. Hydro production continued above normal and at the end of eleven months, the extra production had resulted in a payment to DISCO from GENCO of $21.3 million which was based on the incremental cost for in-province energy only. If the incremental cost had been based on the most expensive energy produced by GENCO, including export sales, the payment to DISCO would have been $71.8 million or $50.5 million more.

When the Board had full regulation of NB Power in the early 1990s it required NB Power to maintain a deferral account to cover such eventualities in that the account could be drawn upon in years when water flows were low and paid into when water flows were above average. DISCO's evidence was that it budgeted for hydro generation energy costs based on a moving 30-year average of water flows.

A public hearing on NB Power's accounting and financial policies was held in October 1990. One matter discussed was the Generation Equalization Account. This account had been established in 1955 and NB Power provided the following rationale for the use of such an account:

> *"Hydro and nuclear units have common cost characteristics in that capital-related charges are very high and fuelling costs are very low. When the energy output from these generating sources falls, most costs continue and the utility must also replace the energy from thermal generating plants that have high fuel costs.*
>
> *These cost characteristics of hydro and nuclear units mean that costs between periods can experience large fluctuations due to certain factors, which are largely beyond the control of the utility, relating to water flow conditions or nuclear unit performance. NB Power believes that customers in any given time period should receive the benefit of average performance from these high quality generating assets, as a matter of inter-generational equity. The utility further believes that*

stabilization of costs is essential to avoid the rate volatility that would be required to actually track generation costs period-by-period.

To treat customers in each time period equally, and stabilize rates, NB Power determines its revenue requirements each year on the assumption that average water flows and average nuclear unit performance will be realized. This is done even if there is reason to believe performance in either case will be above or below average levels." (Exhibit NBP 1, page 5-6 and 5-7, June 22, 1990)

The Board, in its decision dated May 22, 1991, concluded that the principle of adjusting NB Power's annual operating results so as to equalize the operating performance of the nuclear and hydro units was appropriate.

NB Power continued to use the Generation Equalization Account until April 1, 1994. At that time, the company ceased making adjustments to the account and the existing balance of $164 million was credited to income over the three years 1994/1995, 1995/1996 and 1996/1997. This was done on the company's own initiative without any approval from this Board. The effect was to increase net income and reduce the need for rate increases in those three years. However, the result was that this account was no longer available to help stabilize rates after the 1996/1997 year. The Board considers it unlawful that the regulatory reserve accounts approved by it in the early 1990s were eliminated without its approval.

DISCO, as the successor to NB Power in respect of distribution, offered no substantial explanation of why such accounts had been discontinued without Board approval.

The Municipals suggested the Board re-establish such an account for the test fiscal year of 2006/07 and cited subsections 101(1) and 101(4) of the Act as authority for the Board to do so. The PI suggested that such an account be established for fiscal year 2005/06 and have application from that fiscal year forward. In addition he requested that a portion of such new account be used to offset the revenues and rates approved by the Board for 2006/07. VCSJ and the CME suggested the Board re-establish such account.

DISCO Applicant said it had no problem with the Board establishing such an account for the fiscal test year of 2006/07 as the Act clearly allows it. The Applicant cautioned that the Board could not impose it for fiscal year 2005/06 as that would be a retroactive decision of the Board. In addition, DISCO argued that adopting the PI's suggestion and applying a portion of the 2005/06 so called windfall revenue to fiscal year 2006/07 to offset the revenues and rates for that year, would be contrary to the provisions of the Act which entitle DISCO to full recovery of all its forecasted energy costs for 2006/07 as provided for in subsection 101(3) of the Act.

The Board is of the opinion that it has the authority to establish a hydro adjustment or deferral account for the test year 2006/07. However, the Board is not going to do so at this time. Neither DISCO nor the Intervenors addressed an issue that is of concern to the Board related to the establishment of such an account. The Board is concerned that the restructuring of NB Power and the creation of the PPAs place DISCO one step removed from GENCO's hydro generation system revenues. Due to section 156 of the Act the Board has not been able to review the relationship between those revenues and GENCO's energy charges to DISCO contained in the PPAs. Without sufficient detail the Board cannot determine the relevant conditions that should be applied to such an account.

Further, the Board considers that there is insufficient evidence, in this proceeding, to properly do so. It believes that parties should have an opportunity to fully discuss how such accounts would be established and how they would operate before the Board orders that they be established. Accordingly, the Board directs DISCO to file with the Board a proposal outlining how such an account could be established together with suggested terms and conditions for its operation at the time DISCO next makes application to the Board for approval of rates and revenues. This proposal should address at least the following matters:

a. The ability of the Operating Committee to interpret the contract,
b. The need for a reserve account to be established and the purpose of such an account,
c. The relationship between adjustments related to hydro flows and those related to export sales and
d. Whether it would be appropriate to have a reserve account related to energy production from the Point Lepreau nuclear generating facility.

Capital Expenditures:

The Board is concerned that the Act does not contain an express provision allowing it to review proposed capital expenditures of DISCO. Prior to the enactment of the Act the Public Utilities Act contained provisions which required NB Power to apply to the Board for a recommendation in respect of capital expenditures which would exceed $75 million dollars. The Board conducted hearings in respect of the Point Lepreau refurbishment and the Coleson Cove upgrade. Upon the proclamation of the Act those provisions of the Public Utilities Act were repealed and no comparable provisions were included in the Act.

Capital expenditures incurred and proposed by a utility are critically important to the revenue review and rate approval process. The Board does not have general supervision of DISCO. The Board is confined to a review of rates, charges and tolls and then only when an application is made to the Board for a change in them. In this first hearing section 156 expressly precluded the Board's opportunity to review the use and usefulness of DISCO's assets and the prudency of its expenditures. In addition the Board is particularly concerned with capital expenditures being made by or proposed by GENCO as recovery of such expenditures flows directly through to DISCO in the PPAs.

Absent express wording in the Act, the Board finds that it is not in a position, on its own initiative, to conduct periodic reviews of DISCO's or GENCO's actual and proposed capital expenditures independent of a rate application by DISCO.

The Board does, however, have general authority pursuant to section 136 of the Act to require DISCO to provide any information to the Board that it considers appropriate to allow it to properly perform its functions under the Act. DISCO is therefore directed to provide to the Board, on or before October 1, 2006, for the fiscal year 2007-2008 and annually thereafter, a statement outlining in detail its proposed capital expenditures. In addition, the Board directs DISCO to provide the same information in respect of GENCO's proposed capital expenditures for the same periods to the extent that they have been disclosed to DISCO by GENCO.

The Board will conduct a full review of DISCO's actual and proposed capital expenditures as a part of the next rate application made by DISCO. At that time the Board will also review available information in respect of GENCO's actual and proposed capital expenditures to the extent they have been disclosed to the Board.

Recommended Legislative Changes:

As discussed elsewhere in this decision, most of the intervenors, both formal and informal, agreed that the NB Power group of companies today still operates as a vertically integrated utility. Their conclusions are supported, in the Board's opinion, by its review of the shareholders agreement between the government and HOLDCO and by the inclusion of DEBTCO as a party to various PPAs and service agreements. These arrangements effectively inhibit the development of a competitive market for electricity. Most of the intervenors submitted that there is no competitive market for electricity in New Brunswick and further argued that until such time as there is a competitive market, the NB Power group of companies should all be fully regulated by the Board.

The introduction of the so-called three percent cap, which means that the utility can raise its rates up to 3% without appearing before the Board, has contributed to the desperate financial condition in which the NB Power group of companies find themselves. On the basis of this, the Board strongly recommends to Government that a complete review of the Act occur immediately. One of the objectives of such a review would be to provide the Board with normal regulatory tools including general supervisory powers over the NB Power operating companies. This will give the Board the ability to call in any of the utilities at any time it appears that it is in the public interest to do so.

The Board therefore makes the following additional specific recommendations in respect of amendments to the Act:

1 Section 79 should be amended to give the Board authority to initiate, on its own accord, an exit fee hearing.

2 Section 101 should be amended to give the Board authority to regulate the tariff of DISCO, not just its rates, charges and tolls. The Board has this authority in respect of TRANSCO and it makes no sense to limit the Board's authority to a review of just the rates, charges and tolls of DISCO.

3 Sections 98 and 99 should be repealed to ensure that any increase in rates by DISCO is preceded by a public hearing before the Board.

4 Subsection 101(4) should be amended by adding a new paragraph 101(4)(f) to allow the Board to take into consideration energy policies instituted or planned by the Energy Efficiency and Conservation Agency of New Brunswick.

5 Subsection 103(3)(b) should be amended to allow rates to take effect after the expiration of 30 days as presently stated or immediately after the date on which the Lieutenant-Governor in Council modifies or reverses the Board's order, or a

decision is made by the Lieutenant-Governor in Council not to change the decision.

6 Subsection 119(1) should be amended by deleting "and rules" in both the heading and the subsection.

7 Section 120 should be amended to remove "when approved by the Lieutenant-Governor in Council”.

8 Section 128 should be amended to ensure that it has application to the whole of the Act and not confined in operation to Part V.

9 Section 156 should be repealed.

10 The following additional new provisions should be enacted:

(i) Authority for the Board, in its sole discretion, to initiate a proceeding relevant to its regulatory powers provided in the Act.

(ii) Express authority for the Board to initiate, in its own discretion, a review of capital expenditures by GENCO or DISCO.

(iii) Authority for the Board to make interim orders.

(iv) Authority for the Board to revisit a decision upon the request of an affected participant in a hearing.